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Evaluation and Demonstration of Low-NOx Burner Systems for TEOR (Thermally Enhanced Oil Recovery) Steam Generators: Final Report Field Evaluation of Commercial Prototype Burner

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EVALUATION AND DEMONSTRATION OF LOW-NO_x BURNER SYSTEMS FOR TEOR STEAM GENERATORS: FINAL REPORT--FIELD EVALUATION OF COMMERCIAL PROTOTYPE BURNER

by

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16. ABSTRACT The report gives results of the final phase of a program to develop, demonstrate, and evaluate a low-NOx burner for crude-oil-fired steam generators used for thermally enhanced oil recovery (TEOR). The burner designed and demonstrated under this program was developed from design criteria established in bench- and pilot-scale experiments. The report describes the successful installation and testing of a full-scale (16 MWt) commercial prototype burner in the Kern County, CA, oil fields on a conventional TEOR steam generator. A 30-day continous monitoring test demonstrated the capability of the burner to continuously maintain NOx emissions of 70 ppm with CO emissions below 50 ppm and particulate emissions below 0.23 g/dscm. Detailed emission measurements also showed negligible emissions of organic species, including EPA priority pollutants. Thermal efficiency of the steam generator was similar to that prior to the low-NOx retrofit and was within the normal range for conventional steam generators. The mechanical performance of all major burner components was satisfactory.

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Boilers		Stationary Sources	13A	13H
Burners				
Crude Oil			11H, 08G	
Nitrogen Oxides			07B	
Oil Recovery			08I	

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ABSTRACT

The goals of this program were to develop, demonstrate and evaluate a low-NO_x burner for crude oil-fired steam generators used for thermally enhanced oil recovery (TEOR). The burner designed and demonstrated under this program was developed from design criteria established in bench-scale and pilot-scale experiments. This report describes the results of the final phase of the program in which the full scale (16 MW_t) commercial prototype burner was successfully installed and tested in the Kern County, California, oil fields on a conventional TEOR steam generator. A 30-day continuous monitoring test demonstrated the capability of the burner to continuously maintain NO_x emissions of 70 ppm with CO emissions below 50 ppm and particulate emissions below 0.23 g/dscm. Detailed emission measurements also showed negligible emissions of organic species, including EPA priority pollutants. Thermal efficiency of the steam generator was similar to that prior to the low-NO_x burner retrofit and was within the normal range for conventional steam generators. The mechanical performance of all major burner components was satisfactory.

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1.0 SUMMARY

Enhanced oil recovery processes are applied to oilfield production in order to extract heavy, viscous crude oil and tar sands which cannot otherwise be produced. A significant fraction of total U.S. oil reserves require application of enhanced oil recovery in order to be realized. Thermally enhanced oil recovery (TEOR) involves injection of wet steam which is typically produced by combusting crude oil in oilfield steam generators ranging in size from 7 to 15 MW_t capacity. More than 90 percent of all oilfield steam generators in the United States are located in California, approximately one-third of which are located in Kern County. Approximately one-third of the produced crude oil is consumed by the steam generator, amounting to over 200,000 barrels of crude oil consumed per day at full capacity.

The crude oils which are fired in these steam generators are typically high in nitrogen (0.8 to 1.0 percent) and sulfur content. Combustion of these fuels leads to high levels of NO_x and SO_x emissions unless preventive measures are taken. The contribution of fuel-bound nitrogen to NO_x emissions from fuel oil combustion is well documented (1,2). A survey of conventional TEOR steam generators in Kern County (3) showed that uncontrolled NO_x emissions ranged from 160 to 825 ppm (corrected to 3 percent O_2), depending on operating conditions and design variables, with an average emission level of approximately 325 ppm at an average excess oxygen level of 4.5 percent. These high emission levels and deteriorating air quality have prompted state and local legislation regulating NO_x emissions from TEOR generators, which threatens to limit oil production unless NO_x control methods are applied. For certain new or modified stationary sources (including TEOR steam generators) these regulations require application of the Best Available Control Technology (BACT) or the Lowest Achievable Emission Rate (LAER) to control the emission of any air contaminant or precursor for which there is a national ambient air quality standard (including NO_2). Additionally, NO_x emissions from all steam generators are currently limited to 130 mg/MJ (about 225 ppm, corrected to 3 percent oxygen). Further reductions to 108 mg/MJ and to 60 mg/MJ (about 190 and 105 ppm) may be required if ambient NO_2

concentrations exceed certain trigger levels. NO_x control techniques including low-NO_x burners, postflame NH_3 injection or other postflame treatment methods (e.g., selective catalytic reduction) have been considered in order to comply with regulations. Enhanced oil recovery operations are projected to expand in Kern County through 1995. The level of NO_x control required to meet both growth and air quality goals has typically been difficult to achieve with available technology while maintaining acceptable carbon monoxide and particulate emissions as well as practical flame conditions within the steamer.

This report describes the final phase of a program which addresses the need for advanced NO_x control technology for oilfield steam generators. A full-scale (15.7 MW_t) burner system has been developed and tested, the concept for which was based on fundamental studies. The design development phase of this program has been extensively documented in a previous interim report [4]. The full-scale burner was constructed and tested in an experimental test furnace prior to being retrofitted to a field-operating steam generator. This report describes the retrofit and testing of the burner on a conventional steam generator firing heavy crude oil in Kern County, California. The emission goals of the program were:

- to develop to commercial scale a low-NO_x heavy fuel oil burner;
- to demonstrate a full-scale burner system for use either as a retrofit or in new units;
- to evaluate the system in the field over a prolonged period of time;
- to achieve NO_x emissions less than 85 ppm and CO less than 45 ppm with low smoke/particulate emissions and acceptable flame shape.
- to ensure acceptance of the technology by the industry.

All of the above program goals were achieved.

1.1 Concept Background and Development

Combustion-generated NO_x emissions can be reduced by combustion modification techniques which involve staging the heat release process. Techniques such as flue gas recirculation strive to control NO formed from molecular nitrogen (thermal NO) by suppressing peak flame temperature, and are only partially effective with nitrogen-containing fuels (5). NO formation from nitrogen in the fuel (fuel NO) is very sensitive to reactant stoichiometry, and can be significantly reduced by initially burning the fuel under fuel-rich conditions. Staged combustion, therefore, involves creating a fuel-rich zone to promote formation of molecular nitrogen from the nitrogen species (HCN, NH_3, NO) evolved as the liquid fuel decomposes, followed by a fuel-lean zone optimized for minimum NO formation.

The mechanisms controlling NO_x formation during staged combustion were identified in a previous study (6) for liquid fuels ranging from distillate oil to residual oil to alternative coal- and shale-derived oils. The key parameters were first-stage stoichiometry, thermal environment and residence time. NO_x was relatively insensitive to second (burnout) stage parameters. These bench-scale studies showed that under optimum staged conditions, NO_x emissions below 100 ppm were possible and were independent of fuel nitrogen content.

Based on the results of the bench-scale studies, prototype combustors were designed and tested at 2×10^6 Btu/hr and 10×10^6 Btu/hr (4,7) to further develop scaling criteria for the design of a full-scale (60×10^6 Btu/hr) burner. These pilot-scale tests confirmed that a staged combustion system could be designed and scaled over a 150:1 range which is capable of achieving less than 85 ppm NO (at 3 percent O_2) firing high-nitrogen residual oil, with low CO and smoke emissions.

1.2 Burner Design

Figure 1-1 illustrates the design of the full-scale burner. Optimization of both the fuel-rich and fuel-lean stages is achieved utilizing

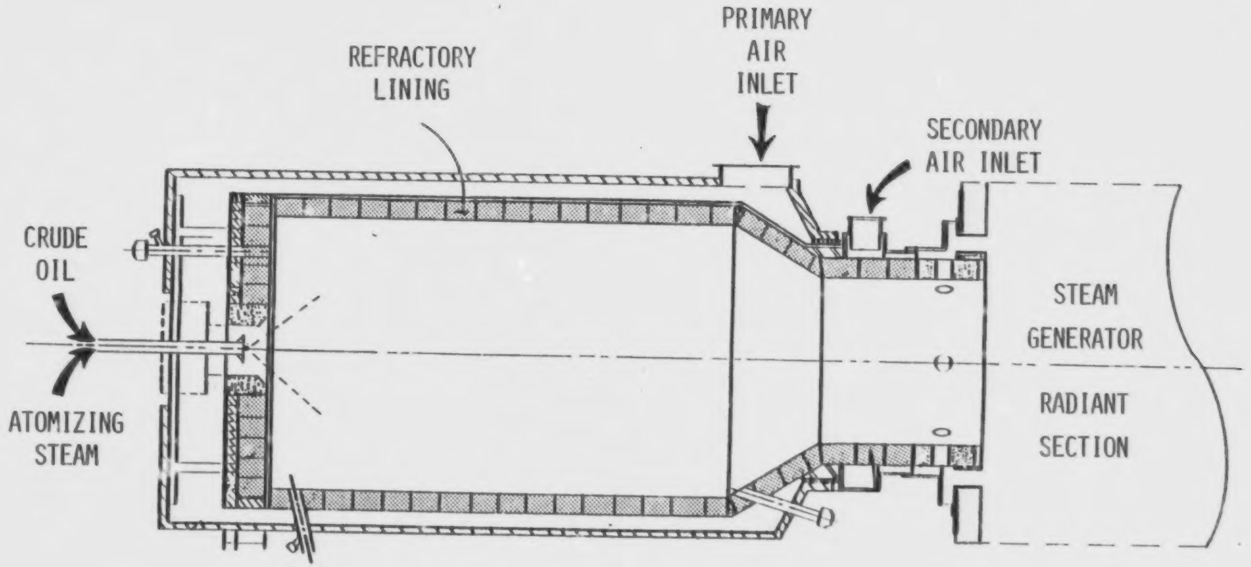

PRIMARY
AIR
INLET
REFRACTORY
LINING
SECONDARY
AIR INLET
CRUDE
OIL
ATOMIZING
STEAM
STEAM
GENERATOR
RADIANT
SECTION

Figure 1-1. Full-scale Commercial Prototype Burner Design

a physically separate first-stage chamber. The first-stage chamber is formed by a 2.1 meters inside diameter horizontal cylinder which is refractory lined and recuperatively cooled in order to maintain first-stage temperature; the exterior of the chamber is also insulated to prevent heat loss to the surroundings. The recuperative design reduces thermal inertia and thermal stresses developed during transient (startup and shutdown) operation by employing a relatively thin layer of refractory. Substantial primary air preheat is developed which enhances full vaporization near the fuel injector.

A commercial air register, ignitor and fuel gun are used in the primary ignition zone. The atomizer is a twin-fluid internal mixing atomizer using steam for atomization. Primary throat diameter was scaled up from the pilot-scale burners on the basis of constant velocity. The exit diameter of the chamber is reduced to provide a first-stage exit velocity of approximately 50 feet per second while reducing radiative heat losses from the first stage.

Secondary air is admitted at the chamber exit through discrete ports oriented parallel to and normal to the burner axis. The distribution of secondary air can be varied to provide some degree of control over second stage mixing. Testing on the bench-scale and small pilot-scale systems had shown that emissions were insensitive to second-stage mixing and excess oxygen level; however, at 2.9 MW_t, results suggested that these parameters may have greater influence on emissions and flame shape in larger systems.

The burner is equipped with a hybrid electropneumatic control system for normal ignition sequences and load modulation. A programmable controller serves to control first-stage stoichiometric ratio and second-stage excess oxygen level for minimum NO_x emissions. The hybrid approach was selected for the reliability and easy field maintenance of a pneumatic system plus the flexibility and more precise control possible with a programmable electronic controller.

1.3 Field Retrofit

After the preliminary burner evaluation was completed in the test furnace, the burner was transported to the host steam generator site in Kern County. The burner had undergone approximately 131 hours of operation during the preliminary evaluation and first-stage parameters had been optimized.

The retrofit task of the demonstration program involved selecting an existing steam generator typical of those currently in operation to host the demonstration, transportation of the burner to the host site, removal of the existing burner hardware and installation of the prototype burner hardware and controls. TEOR steam generators are relatively simple in construction compared with boilers, and utilize a single-pass, drumless design. The radiant section is formed by a horizontal, refractory lined steel cylinder, with the burner mounted on one end and an exhaust transition leading to a convective economizer section on the other end. Steaming tubes extend axially and are supported near the refractory on tube hangers around the generator circumference. The entire unit with feedwater pump and controls is normally skid-mounted and shop-assembled and is shipped by rail car or truck to the installation site.

Retrofit installation of the low-NO_x burner onto the host steamer required replacing the refractory-faced front wall of the radiant section, lengthening the foundation and skid to accommodate the length of the burner, extension of plumbing and electrical wiring, and installation of supplementary controls (e.g., programmable controls, additional limit switches and relays, oxygen probe, etc.). Revised operating procedures to accommodate heatup and cooldown of the refractory lining were also developed. Following completion and shakedown of the retrofit, testing was initiated.

1.4 Field Test Results

The field testing of the steam generator was accomplished in three phases: (1) optimization, (2) detailed characterization, and (3) 30-day evaluation.

The purpose of the initial test series was to optimize the burner operating parameters to achieve safe startup and shutdown, acceptable flame characteristics within the steam generator radiant section, and low NO, CO, and smoke emissions. The steam generator was gradually brought to full load on crude oil. Initial emissions measurements were consistent with results obtained in the test furnace. However, at full load flame impingement on the walls of the radiant section close to the burner was encountered (Figure 1-2). The flame shape was much wider and shorter compared to that obtained in the test furnace. This is most likely a result of smaller furnace diameter in the steam generator.

The initial degree of control over secondary air injection was not sufficient to produce an acceptable flame and other modifications were considered. Although there is a considerable body of literature describing the behavior of confined, double-concentric jets in both nonreacting and flame environments, there is little information for highly confined systems similar to the present burner/furnace combination. The multijet method of secondary air addition also added another degree of uncertainty in attempting to design the optimum modification by classical methods. A very brief series of 1/5-scale, cold isothermal modeling tests was therefore conducted using an existing flow modeling facility in order to evaluate the potential effectiveness of the proposed modifications.

The hardware for the 1/5-scale model was geometrically scaled. secondary air jet velocity was held constant while primary flowrate exit velocity was reduced to maintain the same momentum ratio as at full scale. Flow pattern visualization was achieved with plane illumination and injection of soap bubbles using a commercial neutral-buoyancy bubble generator. Mixing patterns were determined by tracer concentration measurements.

The baseline configuration was evaluated first to determine whether the approach to scaling would produce results similar to field observations. The flow patterns in the model and full-scale steamer appeared to be similar, characterized by a strong external recirculation zone close to the burner exit, rapid expansion of the primary jet toward the wall, and a lazy central

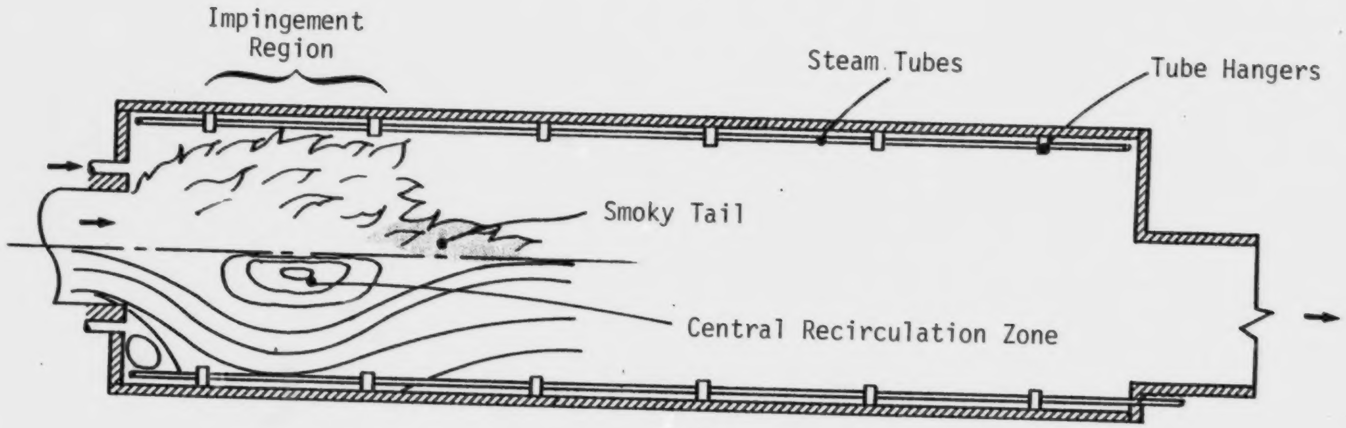
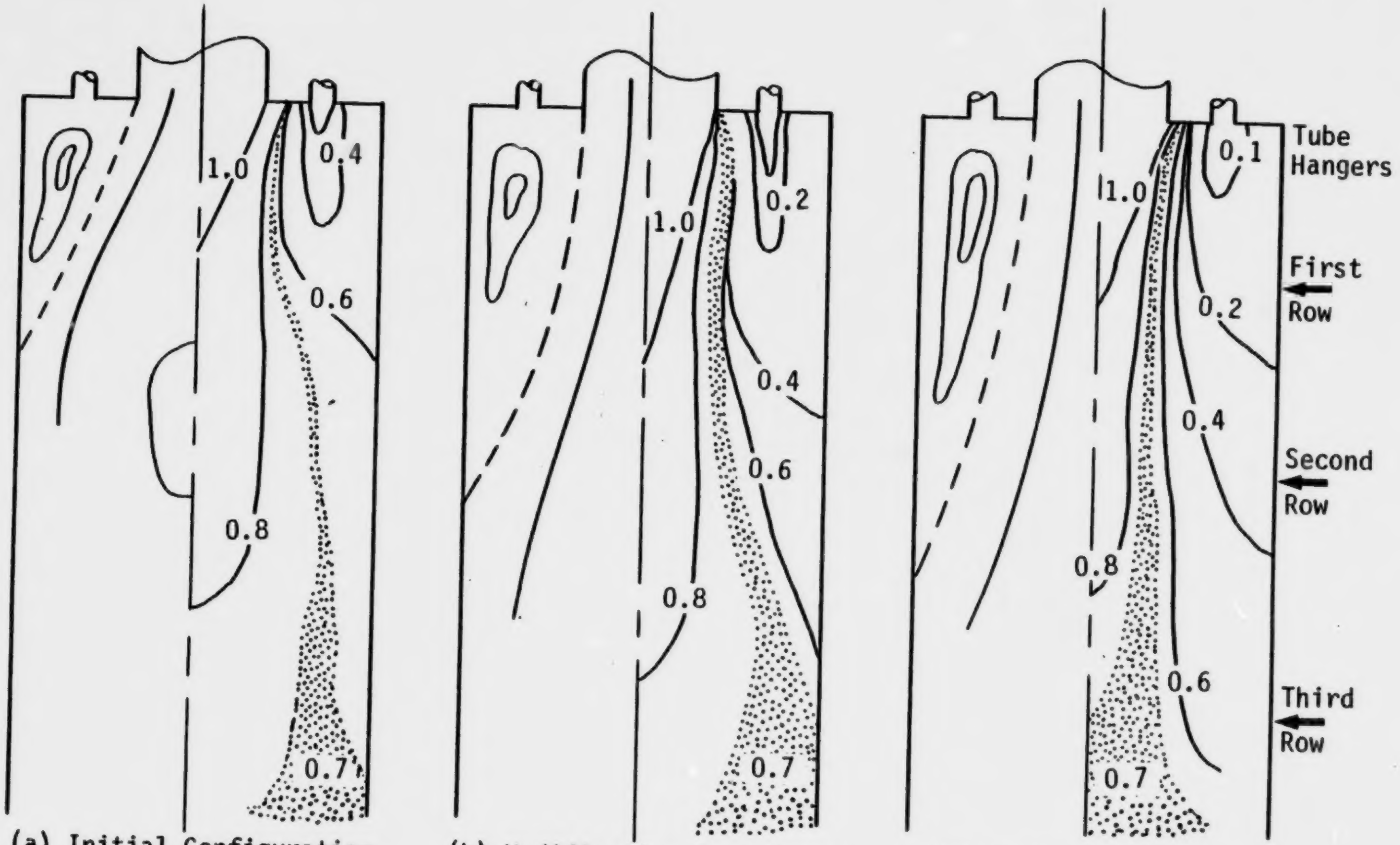

Impingement Region
Steam Tubes
Tube Hangers
Smoky Tail
Central Recirculation Zone

Figure 1-2. Full load flame structure prior to burner optimization.

recirculation zone. The point at which the boundary of the primary streams reached the wall in the model corresponded approximately to the point where flame impingement had occurred in the actual steam generator. The apparent spreading angle of the primary jet boundary was approximately 20 degrees (half-angle). The model also indicated that primary fluid was rapidly entrained into the secondary jets and external recirculation zone very close to the burner exit. Overall, the results obtained with the model in the baseline configuration appeared to be representative of conditions observed in the steam generator.

Figure 1-3 illustrates model results for baseline conditions and two of the modifications which were considered for the full-scale burner. The first modification (1-3b) involved decreasing the first-stage exit diameter. The proposed diameter reduction increased the primary to secondary jet momentum ratio from 0.35 to 0.56. The resulting flow pattern showed that the point at which the primary jet reached the wall was moved 50 percent further downstream, with an apparent spreading angle of 15 degrees. Velocity in the external recirculation zone was somewhat reduced, and the central recirculation zone disappeared entirely. The mixing profiles indicated that the entrainment of primary fluid toward the walls near the burner was significantly reduced. Downstream of the region near the exit both streams appeared to be well mixed, although downstream conditions in the model may not accurately represent full-scale conditions.

A second field modification considered was to remove inserts from the axial secondary air ports thereby enlarging the port area and reducing the momentum of the secondary jets. Figure 1-3c illustrates the flow and mixing patterns obtained with both modifications simulated in the model. This combination resulted in a primary- to secondary jet momentum ratio of 0.99. Reduction of the secondary jet momentum further reduced the apparent spreading angle of the primary fluid boundary to approximately 13 degrees, and significantly reduced the primary fluid concentration at the walls of the model near the burner exit. In spite of the delayed mixing between the streams near the burner, good mixing was still achieved at a distance


1.0
0.4
0.6
0.8
0.7
1.0
0.2
0.4
0.6
0.8
0.7
1.0
0.1
0.2
0.4
0.8
0.6
0.7
Tube Hangers
First Row
Second Row
Third Row

(a) Initial Configuration

(b) Modification 1: Reduced Exit Diameter

(c) Modification 2: Same as Modification 1 Plus Increased Secondary Nozzle Diameter

Figure 1-3. Effect of changing primary and secondary jet momentum on mixing and flow patterns in cold isothermal model.

approximately equivalent to the mid-point of the steam generator, as shown by the region of 0.7 primary fluid concentration.

The results of the isothermal model tests indicated that entrainment of primary combustion products toward the furnace walls close to the burners could be reduced or delayed via modifications to the exit geometry. The rationale for selecting one of the modifications over the others was based on interpretation of the isothermal model results as well as engineering judgement based on experience. Reduction of the primary zone exit diameter appeared to offer reasonable potential for reducing entrainment without adversely affecting downstream mixing. Additionally, if the result of this modification was not satisfactory, the secondary air ports could be enlarged afterwards. Since this appeared to be a reasonable and cost-effective approach, a temporary sleeve of low-grade refractory bricks was installed in the primary exit to increase the velocity of gases at the first-stage exit by 47 percent. The secondary air ports were not changed.

1.5 Burner Optimization

The second series of burner shakedown tests showed that the modification had been successful in eliminating the flame impingement problem completely with all 16 secondary air ports wide open. the visible flame was significantly narrower and slightly longer than the original flame. The center of the flame appeared clear with no signs of smoke or central recirculation zones. Flame shape was similar to the region in Figure 1-3b bounded by the isopleths of 0.6 to 0.7 primary fluid concentration. Overall flame length was approximately 5.5 to 6.1 meters (between third and fourth row of tube hangers). The "tail" of the flame occasionally licked the steam tubes; however, this was considered minor and did not raise concern over tube or refractory life. Since the flame shape produced by the first modification was considered adequate, no attempts were necessary to further improve flame shape, and burner optimization tests were initiated.

Figure 1-4 presents NO_x, CO, and smoke emissions from the steam generator firing at 54 x 10^6 Btu/hr after optimization of second-stage flame

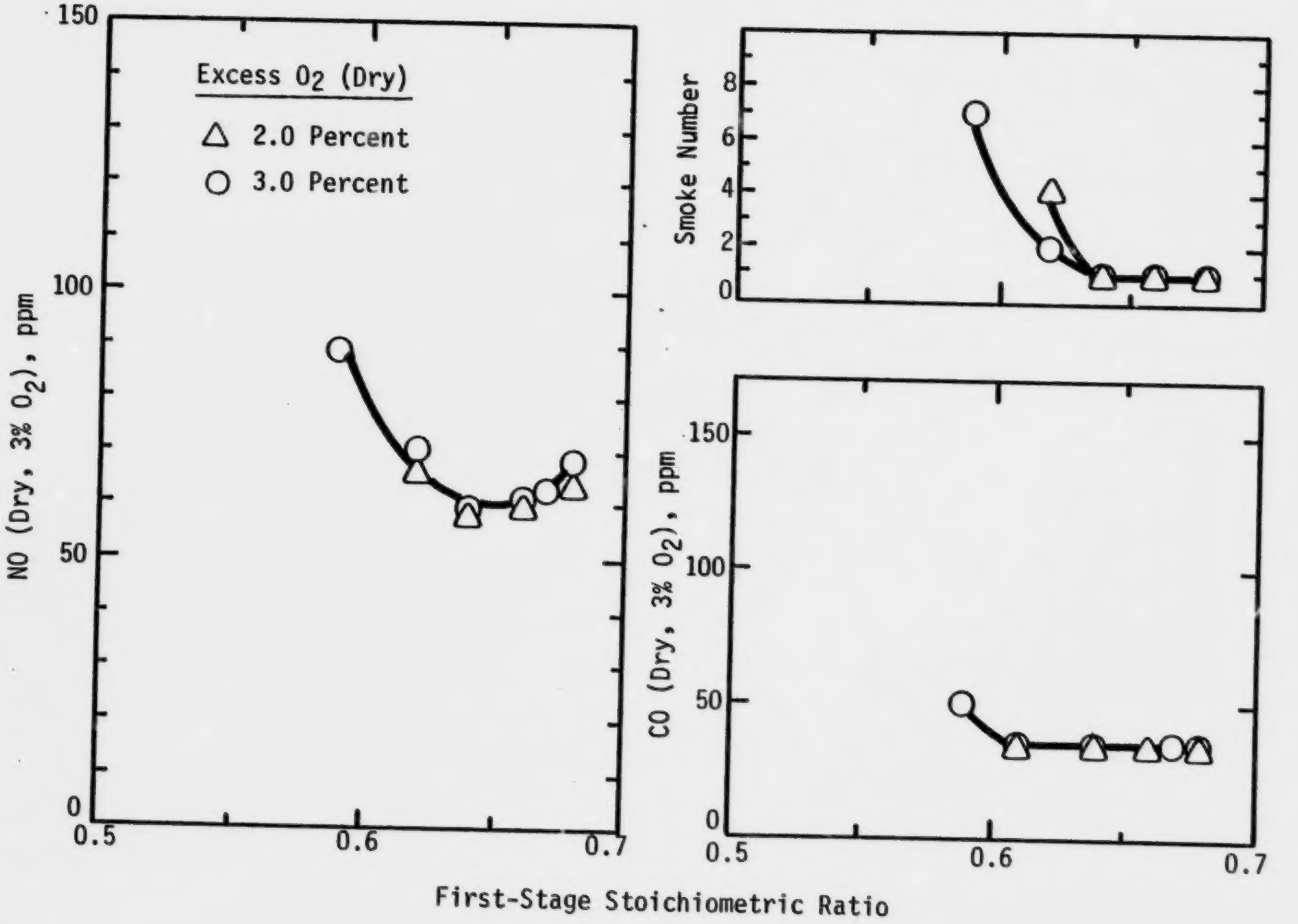


Figure 1-4. Field test results: NO, CO, and smoke emissions from steam generator with optimized burner configuration (54 x 10^6 Btu/hr).

shape. Data are shown versus first-stage stoichiometric ratio for two excess oxygen levels. The fuel was Kern Front crude oil (Table 1-1). Minimum NO_x levels were between 55 and 65 ppm (corrected to 3 percent oxygen). CO and smoke emissions were also low at the optimum stoichiometry; however, below the optimum stoichiometry, smoke was slightly higher for 2 percent excess oxygen than at 3 percent. This behavior was attributed to second-stage mixing; however, since conditions below the optimum stoichiometry do not represent normal operation, no further optimization was required. NO_x and CO emissions were insensitive to excess oxygen. It should also be mentioned that the measured CO emissions were near the detection limit of the continuous (non-dispersive infrared) analyzer and may represent interference by CO_2. Measurements of CO by gas chromatography indicated that true levels were below 1 ppm.

1.6 Long Term Evaluation

Particulates

Based on the results of the optimization tests, ideal operating conditions were programed into the burner control system. A more detailed emissions characterization was performed at the optimum full-load operation point, including particulate mass loading, particulate size distribution, organic compounds, and manual (reference method) gas analyses, in addition to the normal continuous gas analyzers. Total particulate mass loading was determined by three separate methods (EPA method 5, cascade impactors, and modified EPA Source Assessment Sampling System). Results from a total of five measurements ranged from 23×10^3 to 46×10^3 micrograms per cubic meter (0.010 to 0.020 grains per dry standard cubic foot) of flue gas. This is very close to the level expected for quantitative conversion of ash in the fuel. Visual inspection of particulate catches indicated that no carbonaceous particulate was present. Figure 1-5 presents particulate size distribution for the optimum full-load operating condition. Most of the particulate is very fine, with approximately 65 percent below 1 micron.

TABLE 1-1. PROPERTIES OF KERN FRONT CRUDE OIL USED IN FULL-SCALE BURNER FIELD EVALUATION.

	Kern Front Crude Oil
Ultimate Analysis (wt %)	
Carbon	85.42
Hydrogen	10.88
Nitrogen	0.83
Sulfur	1.05
Ash	0.03
Oxygen (by difference)	1.79
	100.00
Specific Gravity (@ 15° C)	0.978
Viscosity	
SSU @ 140° F	2,450
cp @ 60° C	518
SSU @ 210° F	274
cp @ 99° C	58
Heat of Combustion	
Btu/lb, Gross	18,310
Net	--
kJ/g, Gross	42.6
Net	--

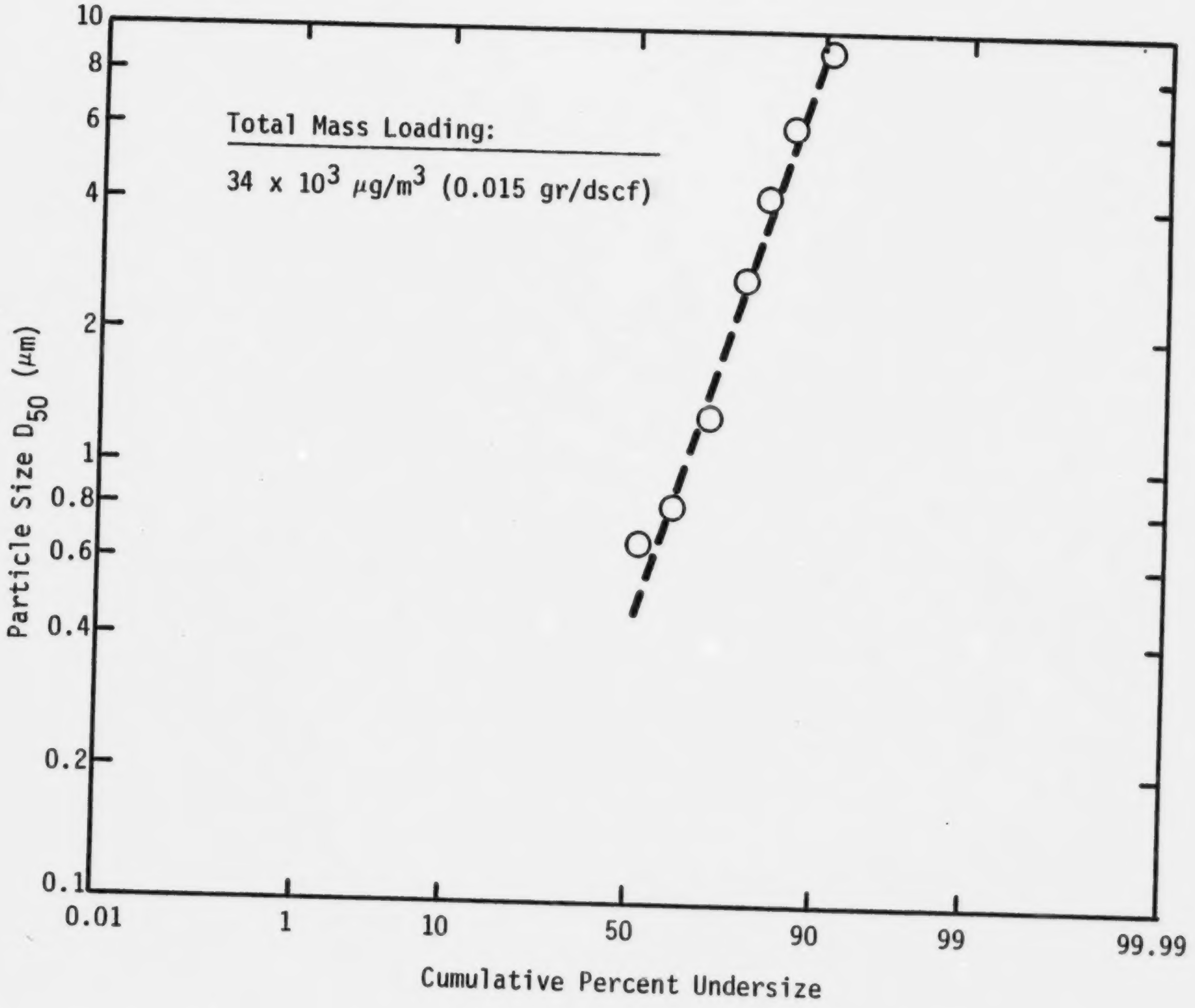


Figure 1-5. Field test results: Particulate size distribution (by cascade impactors) under optimum conditions.

Organic Emissions

Emission of organic compounds was also determined. Total (volatile, semi-volatile and non-volatile) organic compound emissions were below 0.3 milligrams per dry standard cubic meter). Emission of priority pollutants was between 6 and 14 micrograms per dry standard cubic meter. Although no Federal standard has been established for emission of organic species, these levels are considered low for oil-fired sources. Emission of NH_3 and HCN were also low, below 1 ppm.

30-Day Test

Continuous monitoring of NO_x, CO_2, CO, SO_2, and O_2 in the steam generator exhaust was performed during the thirty-day test under EPA Contract 68-02-3188. Complete results were not available at the time this report was prepared. Flue-gas oxygen concentration averaged approximately 2.8 percent (dry-basis) during this period, in agreement with the control system set point.

NO_x emissions averaged approximately 69 ppm during the 9-day period for which detailed data were available and CO emissions remained below 50 ppm. NO_x emissions typically ranged between 56 ppm and 75 ppm (corrected to 3 percent O_2).

SO_x emissions were measured during this same test period. SO_2 concentration ranged between approximately 520 and 650 ppm (corrected to 3 percent O_2) and averaged approximately 580 ppm. These levels are in the range expected based on 100 percent conversion of the sulfur in the fuel.

Preliminary evaluation of results obtained over the entire thirty-day performance test period indicate that these results are typical of the entire period.

Efficiency

Thermal efficiency of the host steam generator was determined before and after the commercial prototype burner was retrofitted. Table 1-2 shows thermal efficiency determined by input-output measurements and by heat loss. In general, the heat loss method is considered to be more accurate because of the smaller errors involved with each of the measurements. Unrealistically high efficiency determined by the input/output method is most likely due to errors in the measurement of steam quality. Data obtained by the host operators prior to the burner retrofit showed heat loss efficiency ranging from 83.6 to 87.8 percent (neglecting unmeasured and radiation losses). Average heat loss efficiency was 85.5 percent. Data obtained during the burner tests prior to the 30-day test showed average heat-loss efficiency of 86.1 percent. Thus it can be seen that thermal efficiency was similar before and after the burner retrofit.

Mechanical Performance

At the completion of the thirty-day test, the burner was inspected to determine the mechanical condition of each of the major components. The burner had undergone over 1600 hours of testing and cycled 20 times, 7 of which were unforeseen shut-downs including 3 power outages. Additionally the burner had survived the rigors of being transported 480 kilometers from the EER test site in El Toro, California, to the host steam generator site.

The overall mechanical condition of the burner was very good at completion of the thirty-day test. One of the key areas of concern was how well the refractory lining had survived the thirty-day test and especially the numerous thermal cycles. Inspection of the refractory lining showed that all refractory including the primary burner throat was in excellent shape, except for a small section of brick on the front wall and the temporary sleeve in the first stage exit. These relatively minor problems have been corrected. The burner control system successfully maintained emissions of criteria pollutants within the program goals for the duration of the thirty-

TABLE 1-2. THERMAL EFFICIENCY OF HOST STEAM GENERATOR.

Date	Heat Release (a) (MW_t)	Excess O_2 (%, wet basis)	Steam (b) Quality (%)	Thermal (c) Efficiency (%)	Flue Gas Exhaust Temperature (° C)	Thermal (d) Efficiency (%)
9/2/82	15.7	3.7	66	80	177	87.1
11/22/82	18.4	3.1	82	82	259	83.6
12/6/82	16.6	2.8	68	80	160	87.8
11/4/83	15.7	2.8	75	86	232	84.8
8/16/83	12.1	2.3	81	91	215	85.1
5/19/83	16.7	2.9	73	93	232	84.8
avg.	15.9	2.9	74	85.3	213	85.5

(a) prior to burner retrofit

Date	Time	Heat (a) Release (MW_t)	Excess O_2 (%, dry)	Steam Quality (b) (%)	Thermal Efficiency (c) (%)	Flue Gas Exhaust Temperature (° C)	Thermal Efficiency (d) (%)
1/5/84	1225	15.7	2.9	83	103	196	86.4
1/7/84	--	15.7	2.9	73	87	204	86.4
1/7/84	0725	15.7	2.9	83	97	210	86.2
1/9/84	0750	15.7	3.0	84	95	234	85.4

(b) after burner retrofit

(a) per barrel of crude oil
(b) by electrical conductivity
(c) input-output--determined by host
(d) heat loss -- determined by EER according to ASME method.
Estimates were used where measurements were not taken.

stoichiometry. Minor excursions in NO_x occurred due to drift in the fuel-flow meter output as a result of changes in ambient temperature. The output of the fuel flow meter is utilized by programmable controller to maintain constant first stage stoichiometry. The drift problem has also been corrected. Performance of all other control elements was satisfactory.

Mechanical condition and operability of the burner was generally satisfactory at the end of the 30-day test.

1.7 Scaling and Applicability

Criteria developed in bench-scale and pilot-scale tests were applied to the design of the full-scale prototype low-NO_x burner. These criteria provide for : (1) optimization of the fuel-rich first stage conditions for maximum conversion of fuel-bound nitrogen to N_2; and (2) optimization of second-stage conditions for minimum thermal NO and smoke formation. The key design criteria are:

1. Fuel Injection
   - High quality atomization.
   - Premixed fuel/air.
   - Minimal heat extraction to maximize fuel vaporization rate.

2. First-Stage Fuel-Rich Zone
   - Stoichiometric ratio approximately 0.7 to minimize total fixed nitrogen (TFN) concentration.
   - Residence time in excess of 400 msec to allow sufficient TFN decay.
   - Control of heat loss to produce a first-stage temperature in excess of 2600°F to promote rapid conversion of fuel nitrogen fragments to molecular nitrogen.

3. Second-Stage Air Injection
   - Partial quenching to minimize thermal NO formation in the second stage.

- Refractory choke to prevent backmixing and reduce heat loss.
- Intermediate to rapid second-stage mixing for minimizing smoke formation, and for control of flame shape.

Full-scale burner tests firing high nitrogen heavy oils in the experimental furnace and in the oilfield steam generator confirmed that the design criteria could be applied to full-scale hardware to produce the expected emissions results. Figure 1-6 compares NO_x emissions from bench-scale, pilot-scale, and full-scale tests versus first-stage residence time. The results represent a 750:1 range in scale. Below approximately 0.6 seconds NO_x emissions increase almost linearly with decreasing residence time. NO_x emissions from the tunnel furnace are slightly higher than the pilot-scale systems due to higher heat losses from the first stage associated with the smaller scale.

Data from the full-scale system indicate that increasing residence time above 0.6 seconds is less beneficial. This asymptotic behavior may indicate a shift in the controlling mechanisms from first stage processes to second stage processes at very low NO_x levels. Earlier pilot-scale tests (4,7) firing nitrogen-free fuels (distillate oil, propane) produced minimum NO_x levels of approximately 40 to 50 ppm from the optimized burner configuration, which was attributed to second-stage thermal NO_x formation. Although full-scale burner performance indicated that emissions exhibited some sensitivity to second-stage parameters (mixing, confinement), this sensitivity is much less severe than typically encountered in conventional systems and the greatest impact is on flame shape.

Figure 1-7 compares NO_x emissions from the prototype burner to field test data (3) for conventional 50×10^6 Btu/hr steam generator burners and for other current NO_x control technology. Average NO_x emissions from conventional burners range from approximately 230 to 280 ppm over the range of excess air investigated. By comparison, emissions from the prototype low-NO_x burner are approximately 65 ppm and insensitive to excess oxygen. This represents a 77 percent reduction over average NO_x emissions at 3 percent excess oxygen, without adverse impact on other pollutant emissions. Low-NO_x

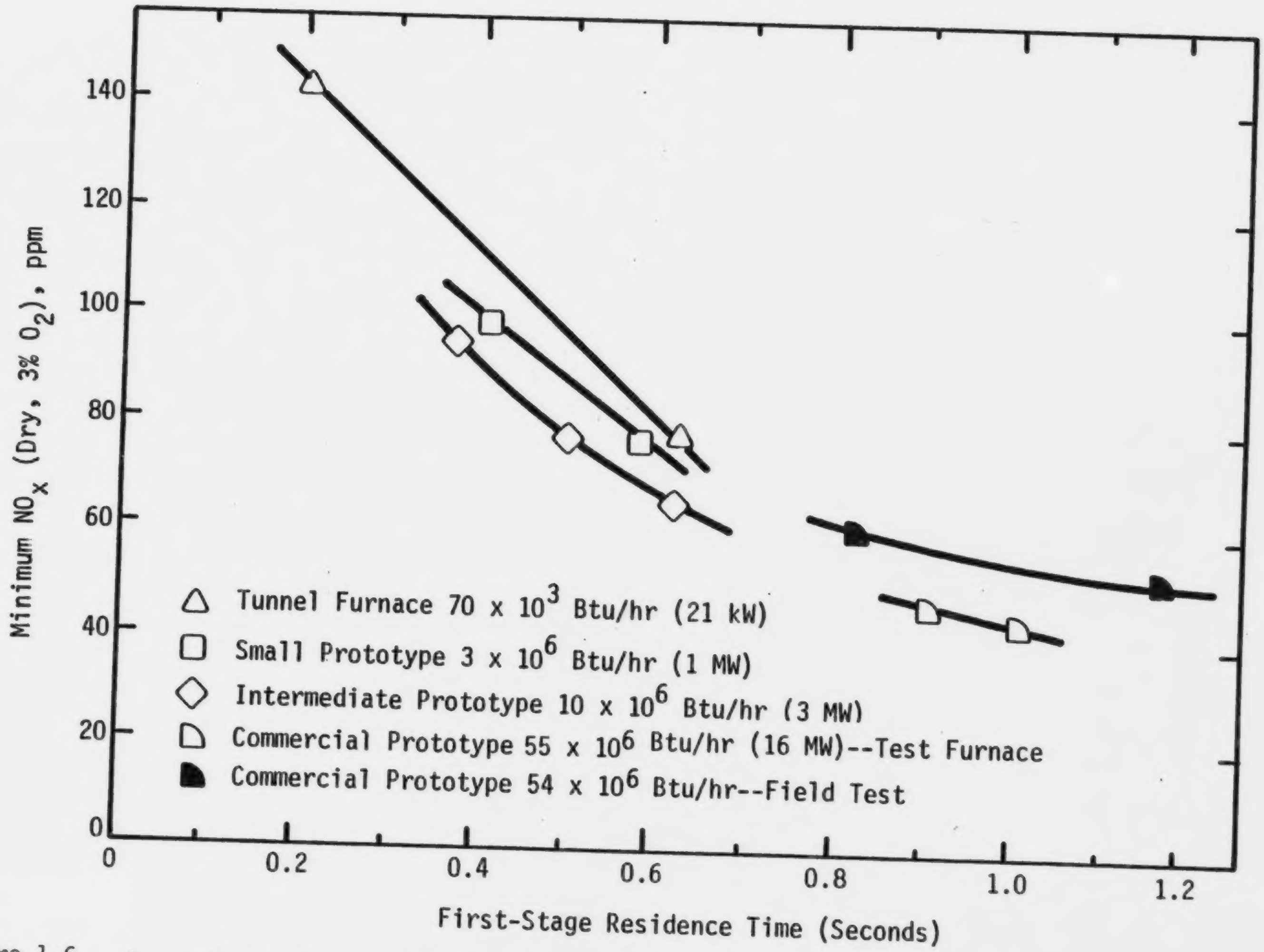


Figure 1-6. Comparison of NO_x emissions from bench-, pilot-, and full-scale prototype burner designs.

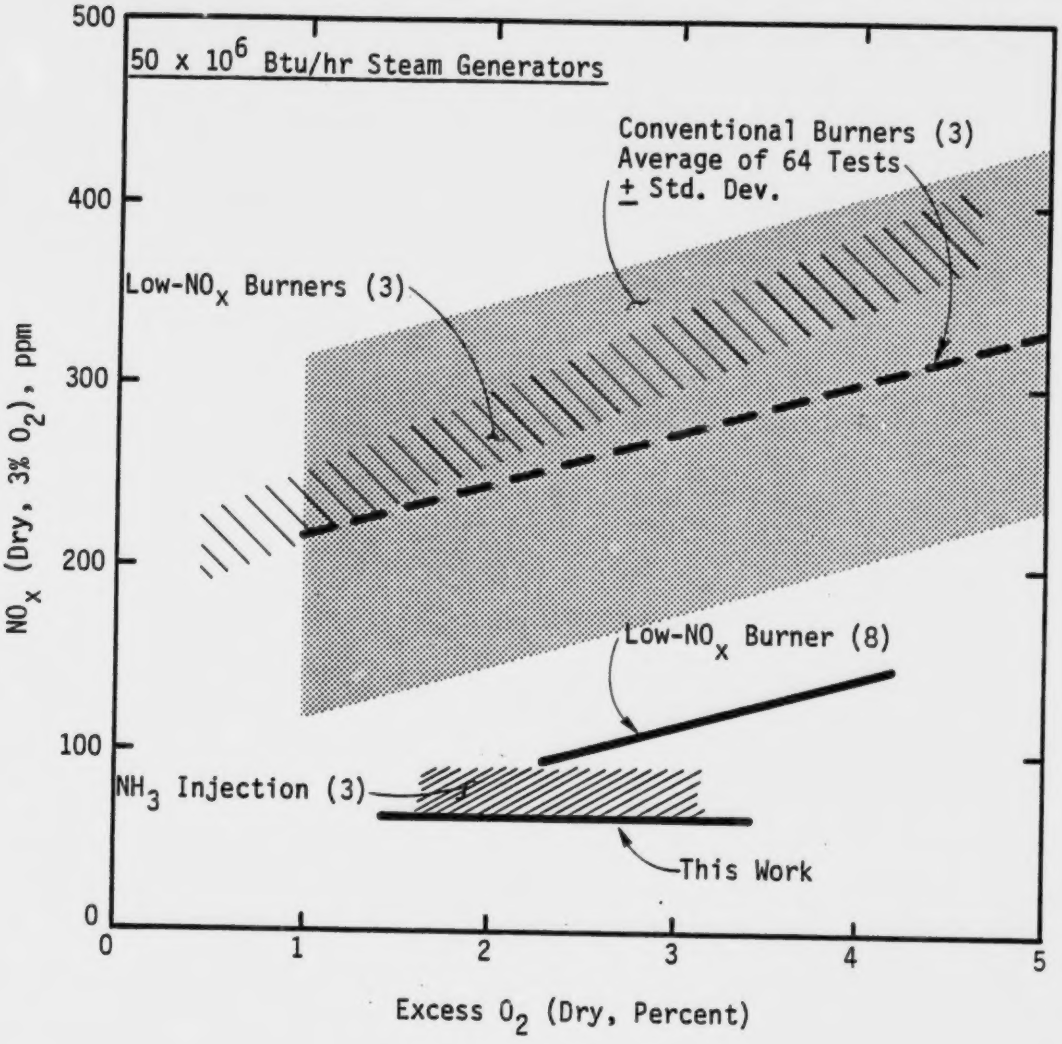


Figure 1-7. Comparison of prototype burner performance to conventional technology and current low-NO_x burner technology.

burner data from Reference 3 indicated that the main benefit of the burners tested was improved operability at low excess air levels. Recent low-NO_x burner technology (8) has shown that significantly reduced NO_x emissions can be achieved by delayed fuel/air mixing within the steam generator in combination with flue gas recirculation; however, the impact of the resulting flame conditions on furnace integrity has not been fully evaluated and some low excess oxygen conditions can result in high CO and smoke emissions. NO_x reduction by postflame ammonia injection into the steam generator radiant section has produced NO_x emission levels comparable to those achieved in this program (3). Test results indicated that it was difficult to maintain optimum ammonia injection conditions over extended periods because of changes in furnace heat transfer caused by tube fouling in the convective section. This could lead to NH_3 breakthrough or higher NO_x emissions. If the practical problems can be resolved these developing technologies may prove to be key to NO_x reduction.

The prototype low-NO_x burner which was developed in this program demonstrates the applicability of the general design criteria developed in bench- and pilot-scale studies. Results of the 30-day test demonstrated that all program emissions goals were met for an extended period of time with no adverse impact on the steam generator performance. At the conclusion of the test program the host management requested that the burner remain installed on the steam generator. Burner performance will be monitored to determine long-term performance and establish operating and maintenance costs.

2.0 BURNER RETROFIT AND SHAKEDOWN

The Commercial Prototype burner was installed on an existing steam generator in service in the Kern Front oilfields near Bakersfield, California. The host steamer was owned and operated by Chevron U.S.A. Retrofit installation of the Commercial Prototype burner in the field required modifications to the existing layout, control system, and plumbing of the steam generator. The retrofit requirements were recognized early on in the burner design which minimized the effort required to execute the retrofit.

The remainder of this section describes the host steam generator characteristics, the modifications which were made, and the results of shakedown testing.

2.1 Host Steam Generator

The host steam generator is described in detail in a previous report (4). The key characteristics of the host site and steam generator will be reviewed briefly before describing the modifications which were made to install the burner. The host generator was manufactured by Struthers Thermo-Flood Corporation and is located in the Kern Front field 13 km (8 miles) north of Bakersfield, California. The host site is owned by Chevron U.S.A., Inc.

TEOR steam generators are single pass, drumless units comprised of a convective economizer and radiant furnace. They are normally factory assembled and skid mounted. The radiant section designs of steam generators are similar. The radiant section of a 15 MW steam generator is a horizontal refractory-lined steel cylinder approximately 12 m long with an inside diameter of about 3 m. Normally 10 to 15 cm of insulating refractory rated for 870 to 1100° C is used. Steaming tubes that extend axially in a serpentine path are supported near the refractory on tube hangers located around the generator circumference. This design allows for heat transfer from the refractory as well as the flame and combustion products. The burner is located at the center of one end of the cylinder and fires directly along its centerline. Under normal operation, there is no flame impingement on the steaming tubes. The burner typically uses about one percent of the generated steam for atomization.

Figure 2-1 shows the overall layout of the host steam generator. The burner end of the skid extends 7.3 meters beyond the burner wall and contains the burner, blower, control console, and feedwater pump. The original burner occupied approximately 4.3 meters between the burner plate and the control console. The existing burner and control console are covered by an overhead roof. The entire unit is 22.5 meters long and 3.5 meters wide. The economizer section is normally transported separately and has no stack.

Table 2-1 lists the design specifications for the host steam generator. The specifications are typical for a unit of this size. Nominal steam capacity is 6.2 kg/s (48,840 lb/hr) at 7.58 MPa. Overall thermal efficiency at nominal operating conditions is 84.7 percent. Steam is saturated and quality is normally 70 to 80 percent since the feedwater is minimally-treated and contains high levels of dissolved solids.

Table 2-2 lists the overall host site characteristics. Several units are located side-by-side and are supplied by a common fuel pump from a 2000-barrel tank. Flue gas exhausts directly to atmosphere; however, a scrubber is planned when additional generators come on line. An access road surrounds the host site.

The composition of the Kern Front crude oil which is fired in this steam generator is given in Table 2-3. The fuel contains 0.83 percent nitrogen (by Kjeldahl analysis) and 1.05 percent sulfur. The characteristics of the Kern Front crude oil are fairly typical of heavy crudes in California.

The steam generator control system includes a conventional electric flame safety/interlock system and burner heat release is modulated with a pneumatic drive system. The flame safety/interlock network provides for the correct starting and shutdown sequence including prepurge, pilot and main

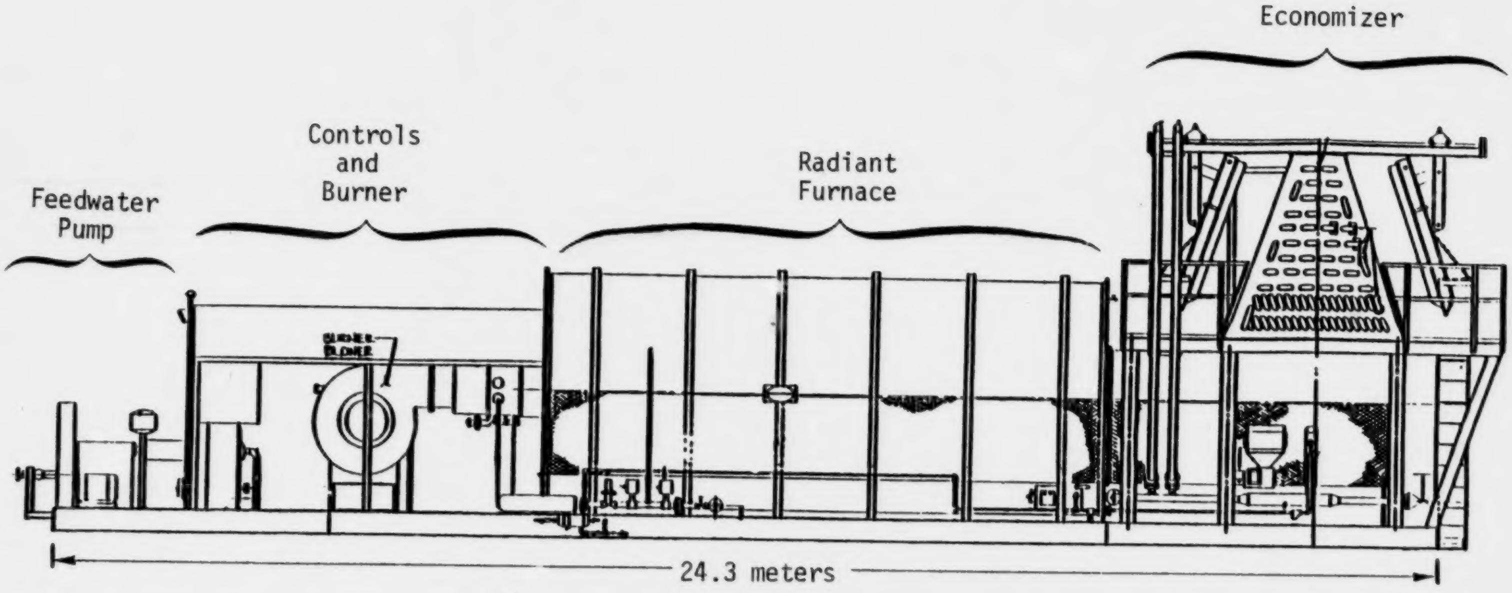

Economizer
Controls
and
Burner
Radiant
Furnace
Feedwater
Pump
24.3 meters

Figure 2-1. Host steam generator layout prior to field retrofit.

TABLE 2-1. HOST STEAM GENERATOR CHARACTERISTICS

Manufacturer/Model:	Struthers Thermo-Flood OH50
Burner:	North American 6131G-62.5
Date of Manufacture:	1981
Steam Output:	14.5 MW 6.2 kg/s
Fuel Input:	17.1 MW (Gross)
Overall Thermal Efficiency:	84.7% *
Exit Flue Gas Temperature:	204°C (at 18 percent excess air)
Radiant Section:	Internal Tube Bend Design
Inside Diameter:	2.91 Meters
Inside Length:	11.3 Meters
External Diameter:	3.4 Meters
Volumetric Heat Release:	0.23 MW/m^3
Tube Surface Heat Flux:	51 kW/m^2
Atomizing Steam Supply:	170 kg/hr
Fuel Preheat Capacity:	150°C
Pilot:	Spark-Ignited Natural Gas

* input-output efficiency based on gross heat release.

TABLE 2-2. HOST STEAM GENERATOR SITE CHARACTERISTICS

Owner:	Standard Oil of California
Location:	Kern Front Oil Field
Nearest Town:	Oildale--approx. 8 km (5 miles) Bakersfield--approx. 13 km (8 miles)
Number of Steam Generators:	2 (total) Operating 5 (total) Planned 10 (total) Future
Generator Orientation:	Side by Side
Space Limitations:	Approximately 5.6 Meters Between Generators Approximately 3 Meters From Burner End of Skid to Road Edge
Fuel Storage Capacity:	2000 Barrels

TABLE 2-3. PROPERTIES OF KERN FRONT CRUDE OIL AT HOST SITE.

Ultimate Analysis (wt%)	
Carbon	85.42
Hydrogen	10.88
Nitrogen	0.83
Sulfur	1.05
Ash	0.03
Oxygen (by difference)	1.79
	100.00
Specific Gravity (@ 15/15° C)	0.978
API Gravity (@ 15° C)	13.2
Viscosity (cp)	
@ 60° C	518
@ 99° C	58
Heat of Combustion	
Gross (kJ/g)	42.6

burner ignition, postpurge, etc. The pneumatic system controls feedwater flow rate and burner firing rate. The feedwater flow is manually set and burner firing rate follows feedwater flow. Burner firing rate can be manually-biased to adjust steam quality. The pneumatic system automatically reduces feedwater flow and firing rate if steam pressure exceeds a maximum setpoint for safety. A relay logic network sequences the pneumatic systems during startup and shutdown.

2.2 Steam Generator Modifications

Review of the host steam generator characteristics identified the retrofit requirements and constraints which were considered in the burner design and installation. Table 2-4 summarizes the key retrofit constraints. Transport constraints were those weight, height, and width limitations imposed on commercial carriers for burner shipment by truck. The overall layout of the site did not impose extremely severe restrictions except for a nearby access road which limits the allowable skid extension to approximately 3.1 meters. During installation a "field-fit" modification to the feedwater pulsation damper layout was required to allow adequate operator access on both sides of the cab area. Four additional control boxes were added to the cab area.

Most of the existing burner controls were retained in the final installation. Several of the original limit switches were re-used to minimize cost and potential interface problems. Several additional safeguards are built-in to the steam generator logic to minimize damage during an upset and all of these safeguards were retained. In designing the control logic for the Commercial Prototype burner, maximum use of the existing control logic minimized the increase in operational complexity in order to facilitate operator acceptance.

Figure 2-2 illustrates the steam generator layout after retrofit installation. The original burner and burner mounting plate were completely removed along with a section of skid approximately 3.7 meters in length between the burner wall and the control console. The concrete foundation was

TABLE 2-4. SITE-SPECIFIC BURNER RETROFIT CONSTRAINTS AT HOST SITE.

Steamer Design/Site Characteristics	Impact On Burner Design/Installation
1. Transportation	
- shipping requirements	limit weight and dimensions to maximum allowable for conventional transport by rail and truck.
2. Site Layout	
- roadway access	- maximum allowable skid extension of 3 meters.
- adjacent equipment	- diversion of feedwater plumbing
- operator access to cab area	- layout of additional control panels
- access for maintenance and repair	- limited room to increase width
- safety requirements	- overall execution
3. Control System	
- steam generator limits	- selection of interface equipment
- burner limits	- limited increase in complexity or number of operator adjustments
- control hardware	- use of existing limit logic
- operator qualification	
4. Steamer Operation	
- startup/shutdown sequences	- limited operating time for initial refractory heat-up without steam generation
- blowdown pit capacity	
- operator attention	- minimum increase in required operator attention during startup, operation, and shutdown
- atomizing steam consumption	- increase atomizing steam line size
- nearby operations	- coordinate installation efforts

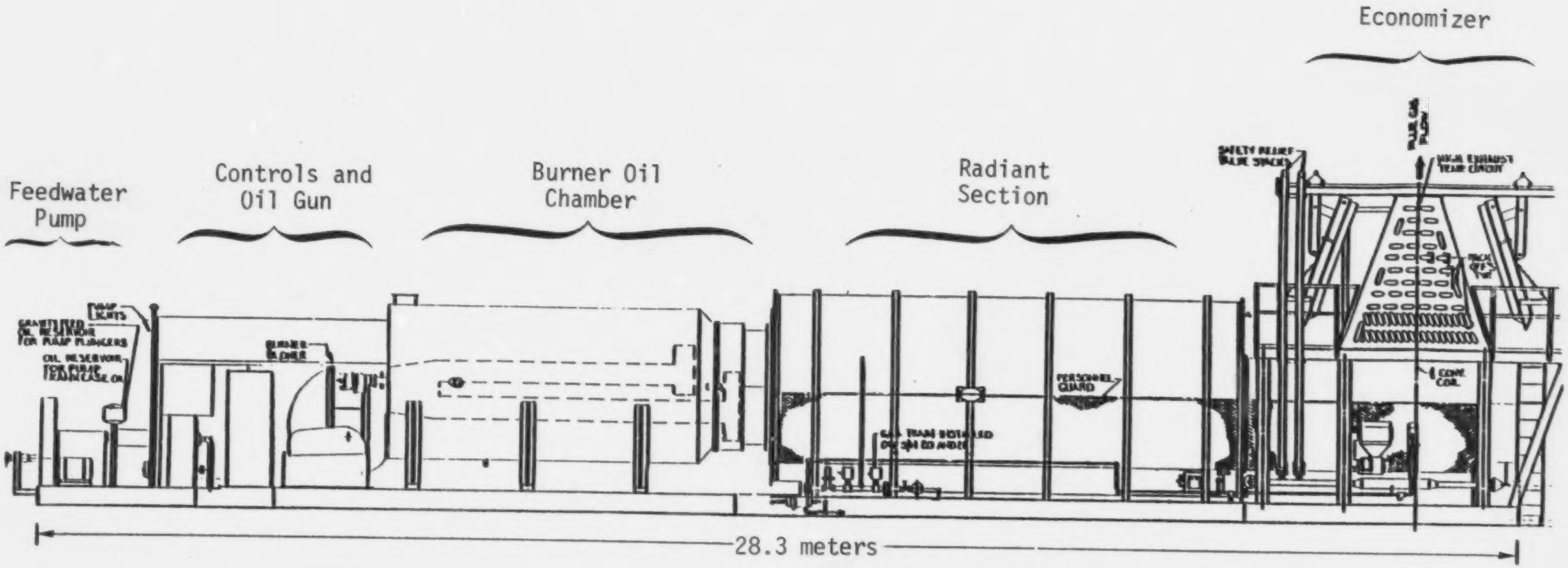

Feedwater Pump
Controls and Oil Gun
Burner Oil Chamber
Radiant Section
Economizer
PUMP LIGHTS
GRAVITY FEED OIL RESERVOIR FOR PUMP PLUNGERS
OIL RESERVOIR FOR PUMP CRANKCASE OIL
BURNER BLOWER
PERSONNEL GUARD
SAFETY RELIEF VALVE STACKS
FLUE GAS FLOW
HIGH EXHAUST TEMP CUTOFF
28.3 meters

Figure 2-2. Steam generator layout after retrofit installation of Commercial Prototype burner.

extended by approximately 4.0 meters to accommodate the increase in burner length. This placed the end of the foundation slightly into the access road; however, this did not unduly restrict routine access via the roadway and was acceptable to the host. A new burner mounting plate and the skid-mounted Commercial Prototype burner were then installed on the host steam generator. The section of skid which contained the original control console and feedwater pump was re-installed behind the new burner skid. The original roof for the cab area was re-installed over the control console and burner area. Electrical control wiring, conduit, and instrument air lines were extended to connect with the control console. The feedwater pump pulsation dampener and high-pressure feedwater lines were extended and relocated to allow operator access to the cab area. The feedwater plumbing modification is illustrated in plan view in Figure 2-3. The modification extended laterally approximately 2.1 meters from the side of the steam generator skid. An access platform was constructed over the feedwater piping. Fuel, atomizing steam and atomizing air were connected to the piping trains on the Commercial Prototype burner. The original fuel shutoff valves, oil flow totalizer and oil return valve were utilized to provide an added margin of safety via redundancy.

The host steam generator was originally equipped with O_2 control equipment. In order to avoid interfacing problems in the field the O_2 probe system which was utilized during preliminary burner evaluation (4) was installed on the host steam generator in the transition section between the radiant furnace and convective economizer. The control installation was completed with the mounting and interconnection of the four additional burner control boxes containing the programmable controller, pneumatic relays, electrical switches and relays, and flow measurement devices. All of the burner installation, plumbing and electrical work was carried out by the steam generator manufacturer's local service branch.

The original steam generator control system logic controls burner firing rate based on the feedwater flowrate by suppling a pneumatic signal from the feedwater flow orifice to the burner fuel valve/air damper linkage actuator through a manual bias relay. The new controls were designed to utilize the

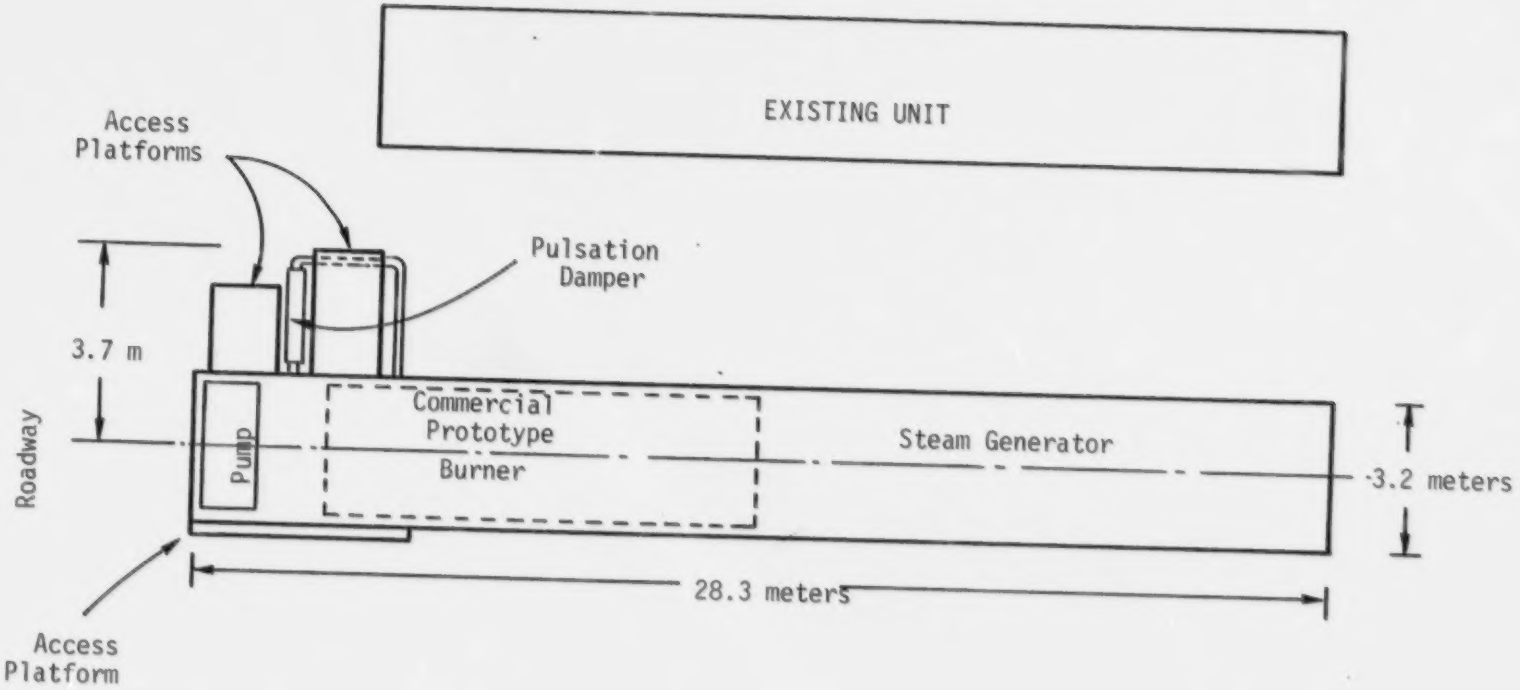
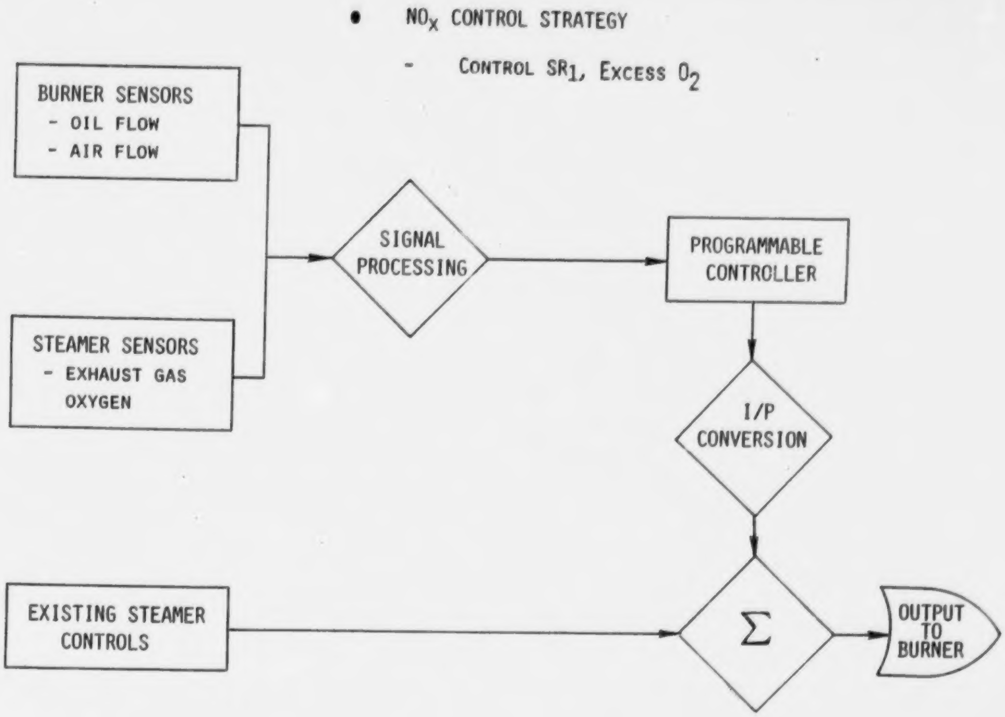

EXISTING UNIT
Access
Platforms
Pulsation
Damper
3.7 m
Roadway
Pump
Commercial
Prototype
Burner
Steam Generator
3.2 meters
28.3 meters
Access
Platform
EXISTING UNIT

Figure 2-3. Plan view of steam generator layout after retrofit installation of Commercial Prototype burner.

same manually-biased pneumatic signal to drive the fuel valve directly and the primary and secondary air actuators through bias relays (parallel positioning). Figure 2-4 illustrates the control logic for maintaining minimum NO_x firing conditions. The new controls were added in parallel to the existing steam generator controls. Once the steam generator is started up the normal manual operating adjustments are identical to conventional steam generators. The new controls automatically meter oil flow, primary air flow, and exhaust O_2 level. These signals are processed by the programmable controller which calculates the actual first stage stoichiometry and excess O_2 level. The controller then compares the actual conditions to the optimum conditions and generates an error signal which biases the primary and secondary air actuators through current-to-pneumatic signal transducers. The bias signal is pneumatically limited to high and low levels in the event of a failure in the feedback loop. Figure 2-5 shows the overall integration of the new controls.

In addition to standard burner operating limit controls the commercial prototype burner includes additional control features as a result of the more complex design requirements. The oil gun is fitted with pneumatic piston actuators which retract the oil gun from the burner throat in the event of a shutdown. This partially shields the oil gun, diffuser, and pilot assembly from thermal radiation from the refractory lining in the prechamber. The burner is also designed to shut down in the event that the inner stainless steel shell temperature exceeds preset limits. Excessive shell temperature will also trigger a "dump" valve to open on top of the burner shell which allows increased air flow to pass over the stainless steel shells, cooling the steel with minimum thermal shock to the hot refractory.

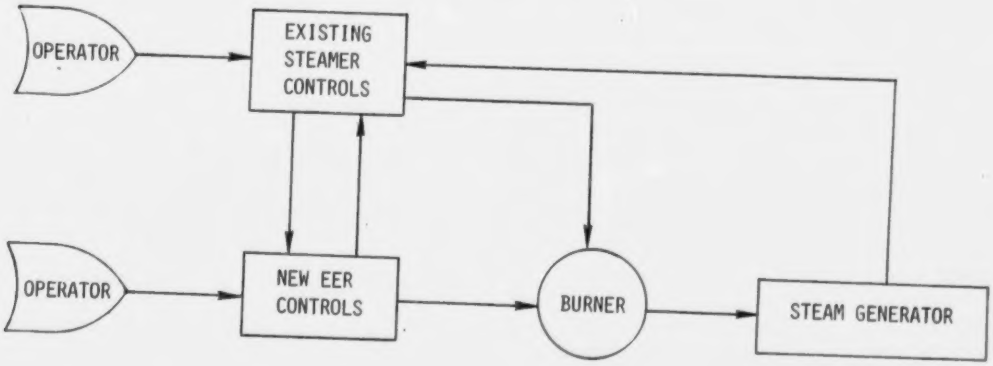
The startup and shutdown sequences pose the most significant difference in burner operation and control between the Commercial Prototype burner and conventional burners. Ideally the burner startup must be executed so that the maximum rate of increase in refractory temperature is limited to approximately 260°C per hour in order to achieve reasonable refractory lifetimes. In practice the actual operation is a compromise. The recommended startup sequence is outlined in Figure 2-6. Startup typically



- NO$_x$ CONTROL STRATEGY
  - CONTROL SR$_1$, EXCESS O$_2$

BURNER SENSORS
- OIL FLOW
- AIR FLOW
STEAMER SENSORS
- EXHAUST GAS OXYGEN
SIGNAL PROCESSING
PROGRAMMABLE CONTROLLER
I/P CONVERSION
EXISTING STEAMER CONTROLS
Σ
OUTPUT TO BURNER

CONTROLS INTEGRATION



OPERATOR
EXISTING STEAMER CONTROLS
OPERATOR
NEW EER CONTROLS
BURNER
STEAM GENERATOR

Figure 2-4. NO$_x$ control logic for Commercial Prototype burner.

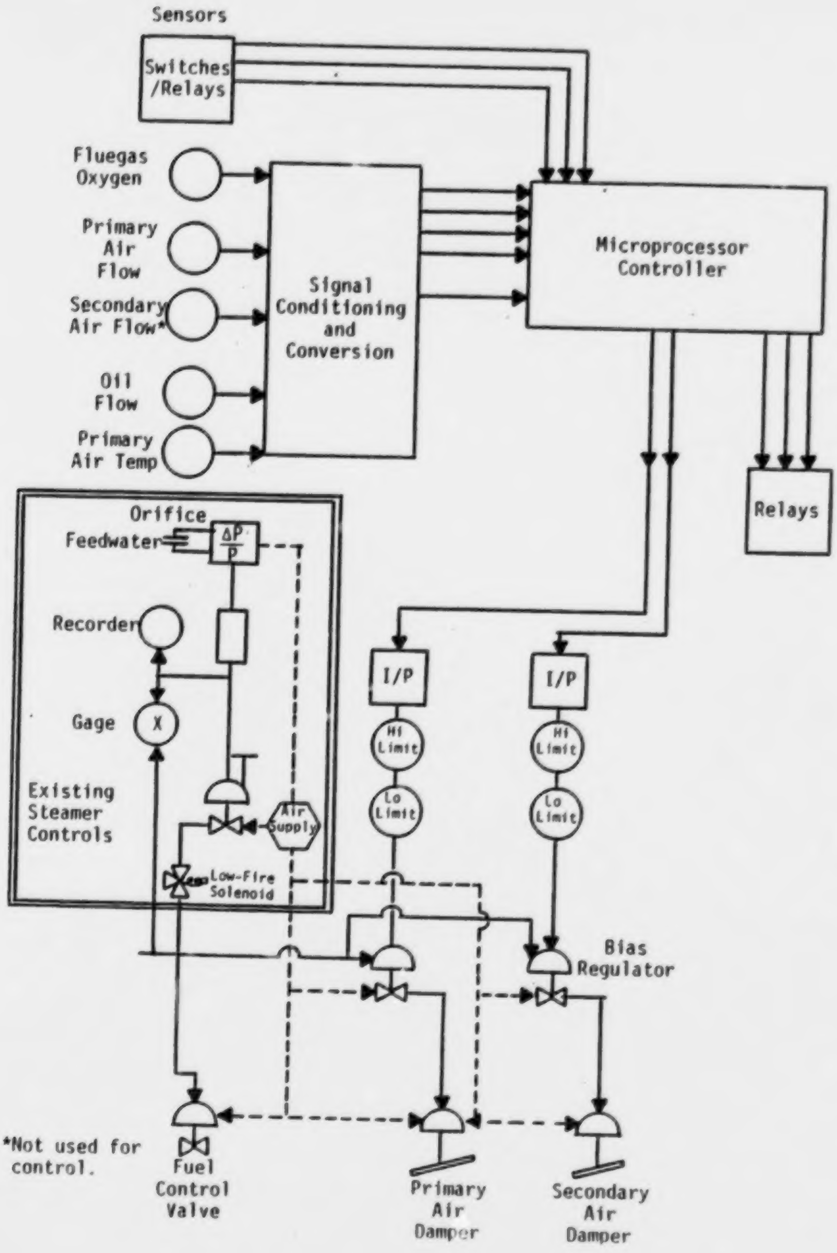

Sensors
Switches /Relays
Fluegas Oxygen
Primary Air Flow
Secondary Air Flow*
Oil Flow
Primary Air Temp
Signal Conditioning and Conversion
Microprocessor Controller
Relays
Orifice
Feedwater
ΔP/P
Recorder
Gage
X
Existing Steamer Controls
Air Supply
Low-Fire Solenoid
I/P
Hi Limit
Lo Limit
I/P
Hi Limit
Lo Limit
Bias Regulator
*Not used for control.
Fuel Control Valve
Primary Air Damper
Secondary Air Damper

Figure 2-5. NO_x controls integration.

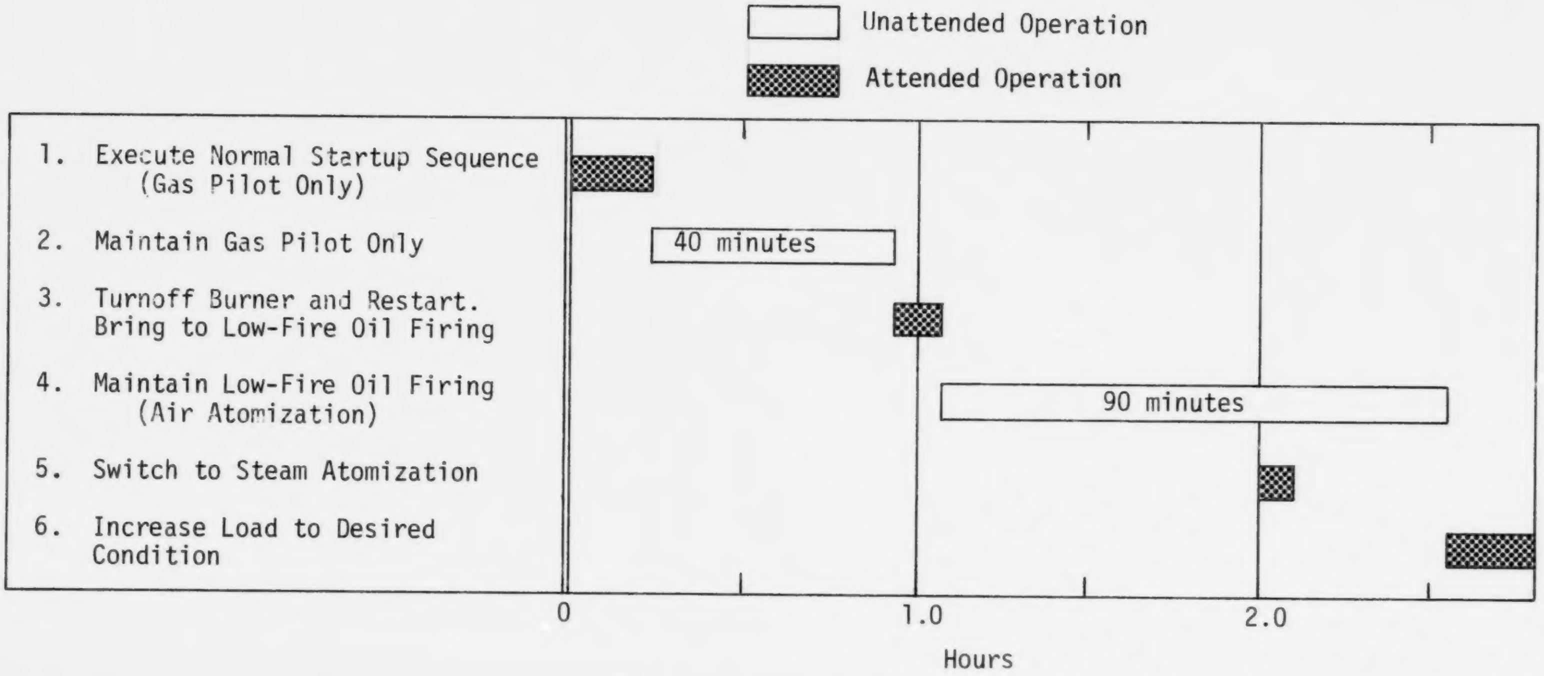


Figure 2-6. Revised startup sequence for Commercial Prototype burner.

begins with initial checks amd adjustments by the operator to insure correct valve and switch positions as well as for proper equipment condition prior to initiating the burner ignition sequence. The first phase of startup involves ignition and operation of the gas pilot only for approximately 40 minutes. The gas pilot has a firing capacity of approximately 0.79 MW_t. After the 40 minute period on the gas pilot, gas temperature at the exit of the refractory chamber has reached approximately 425°C. The burner is then shutdown, restarted, and switched to low-fire oil operation with air atomization. The burner is held at low fire (41 MW_t) for approximately 90 minutes. After approximately 45 to 60 minutes on low fire the steam pressure is sufficient to switch from air to steam atomization. After 90 minutes at low-fire, the burner can slowly be brought up to the desired operating condition. Steady-state temperatures in the prechamber are not achieved for several hours; however, this does not affect operation of the steam generator.

Burner shutdown must also be executed over an extended period, as shown in Figure 2-7. The objectives of the shutdown are also to minimize thermal shock to the refractory lining as well as to prevent excessive steel temperature at the inner shell. During most of the startup and shutdown periods operator attention is required only when a change is made. Constant supervision is not necessary. During the initial phase of the startup sequence and final phase of the shutdown sequence, heat input is not sufficient to generate steam. The feedwater cannot be throttled completely and therefore is bypassed to a blowdown pit at the host site during these periods. The final stage of the shutdown sequence includes a 2-hour post-purge to partially cool the prechamber.

2.3 Shakedown Testing

The objectives of the shakedown tests were to identify and correct miscellaneous installation problems and to perform control system calibrations. After the final adjustments to the control system were completed, a series of "dry run" burner trials were executed to verify and debug operational problems. Minor problems, such as electrical wiring errors, were resolved and the first burner ignition trials began.

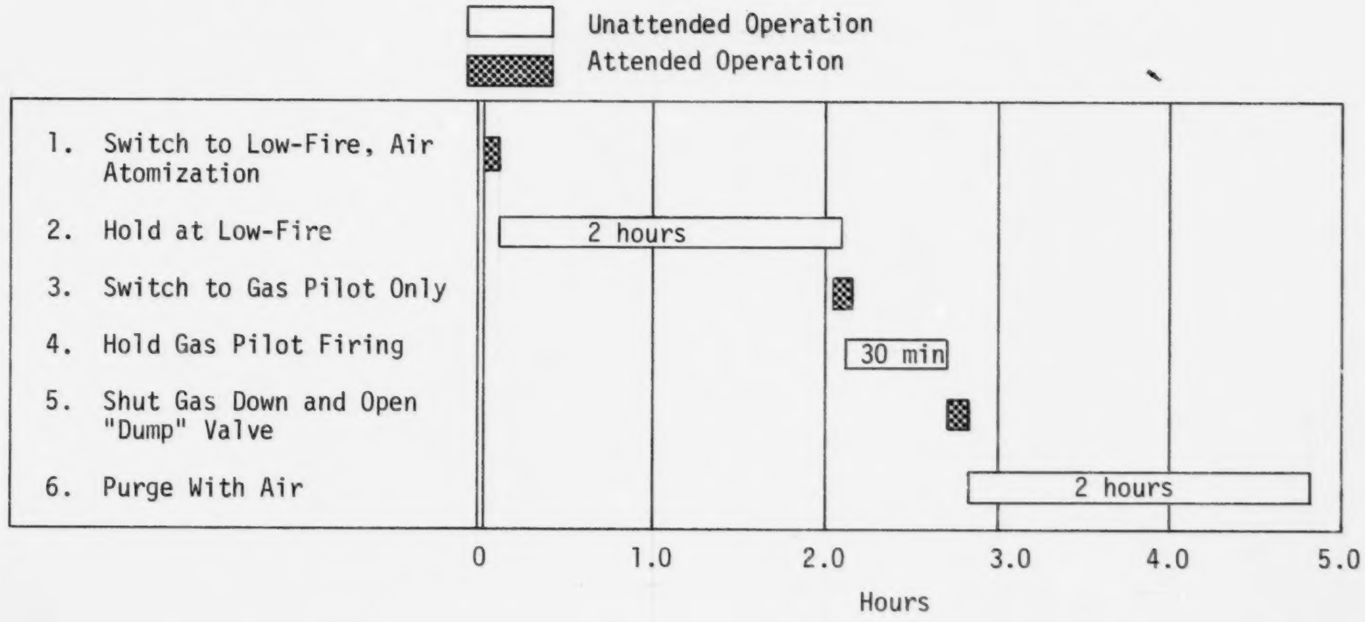


Figure 2-7. Revised shutdown sequence for Commercial Prototype burner.

The tests began with pilot ignition trials. These proved satisfactory and, after a warmup period had been identified, the burner was ignited on crude oil. Gas temperature was monitored at the exit of the first stage chamber. Load was progressively increased until the gas temperature reached approximately 1100° C. The burner was then shutdown slowly. Several minor repairs and adjustments were carried out. After inspection of the burner refractory and the steam tubes in the radiant section of the steam generator, the burner was started again and brought to full temperature. Load was progressively increased after achieving near steady-state temperature at the first stage exit at each load step. The burner control system was adjusted so that air flow was maintained constant below approximately 75 percent load, as shown in Figure 2-8. This approach was selected to achieve adequate shell cooling at low load and results in unstaged operation below approximately 40 percent load. Above 75 percent load, SR_1 is maintained at the optimum level to achieve minimum NO_x emissions.

At this point in the shakedown tests attention was focused on second stage flame shape in the steam generator radiant section. A second-stage flame was not visible until load reached approximately 9 MW_t. At 10 MW_t, the flame was short, wide and well-defined. There appeared to be a large reverse-flow zone in the center of the flame. At 13 MW_t, hard flame impingement was visible on the walls of the radiant section close to the burner. The observed flame shape is illustrated in Figure 2-9. The flame was very wide, approximately 3.5 to 4 meters in length and there appeared to be a large, smoky reverse-flow region in the center. NO_x emissions were approximately 60 ppm, corrected to 3 percent oxygen and CO emissions were about 30 ppm. Smoke number was 7. After several tests it was concluded that the flame impingement was a result of (a) high secondary to primary fluid momentum ratio, and (b) the narrow diameter of second stage. The entrainment requirements of the secondary air jets must be satisfied internally by primary combustion products and externally by fluid from the recirculation zone surrounding the burner exit. Since the system is highly confined ($D_f/d_e = 1.6$) the mass flow in the external recirculation zone is limited and additional fluid from the center of the flame is entrained into the secondary air jets to compensate. The high secondary air jet momentum and high degree

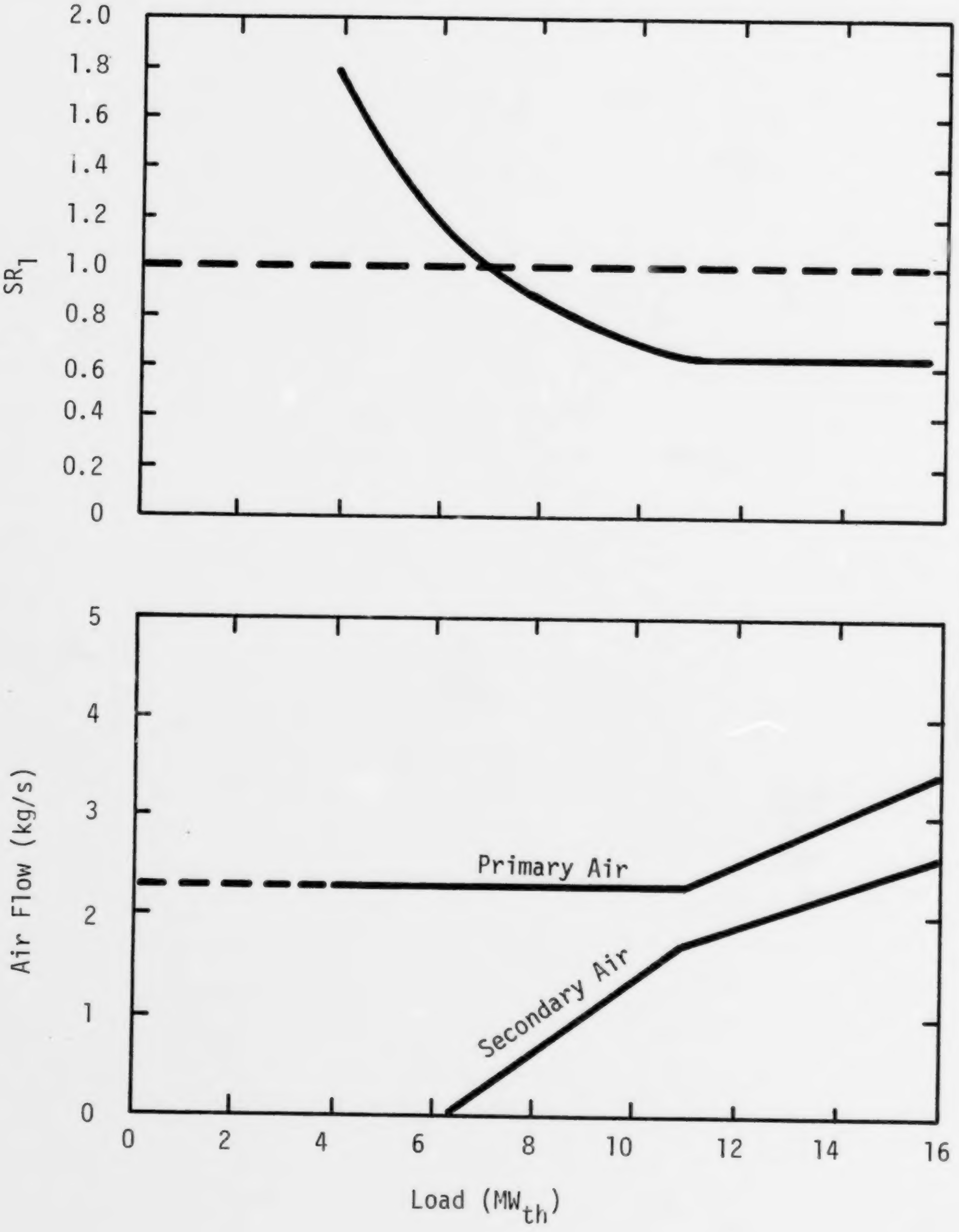


Figure 2-8. Primary and secondary air flow control logic.

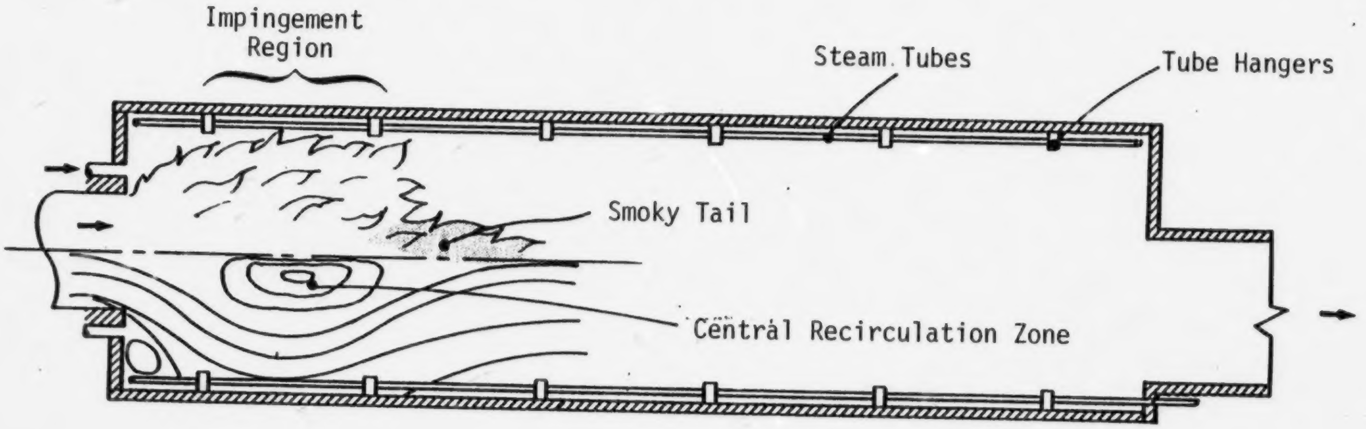

Impingement Region
Steam Tubes
Tube Hangers
Smoky Tail
Central Recirculation Zone

Figure 2-9. Full load flame structure.

of confinement effectively cause the primary combustion products to be pumped toward the walls of the furnace before combustion is complete.

The flame shape observed in the steam generator was much different from the flame shape observed previously with the same burner configuration in the Medium Tunnel test furnace during the preliminary evaluation $^{(4)}$. The flame produced in the test tunnel was approximately 6 meters in length and 2.2 meters in diameter, with no visible central recirculation zone. The flame produced in the steam generator was approximately 3.5 to 4 meters in length and 2.8 meters in diameter. This difference most likely results from the different internal diameter of the Medium Tunnel furnace and steam generator radiant section. In the Medium Tunnel, D_f/d_e was approximately 2.4. This suggest that flame length from the Commercial Prototype burner is approximately proportional to furnace diameter.

2.3.1 Burner Modifications

The secondary air ports were constructed to allow on-line variation of air velocity, and each of the sixteen axial air ports could be opened or closed independently. The degree of control achievable with these port variations was not sufficient to eliminate the flame impingement problem. Several hardware modifications to the burner exit geometry were considered. Although there is a considerable body of literature describing the mixing characteristics of confined, double-concentric jets in both non-reacting and flame environments, there is little information available for highly-confined systems similar to the present burner/furnace configuration. The addition of secondary air through discrete jets rather than a continuous annulus also complicates analysis of the current configuration by classical methods. In order to maximize the chances for success in making any costly modifications, a series of cold isothermal modeling tests was conducted.

The tests were carried out in the Small Spray characterization facility (SSR) illustrated in Figure 2-10. The internal diameter of the SSR is 61 cm which is approximately 1/5 the size of the steam generator radiant section. A geometrically-scaled 1/5-scale mock-up of the primary exit geometry was

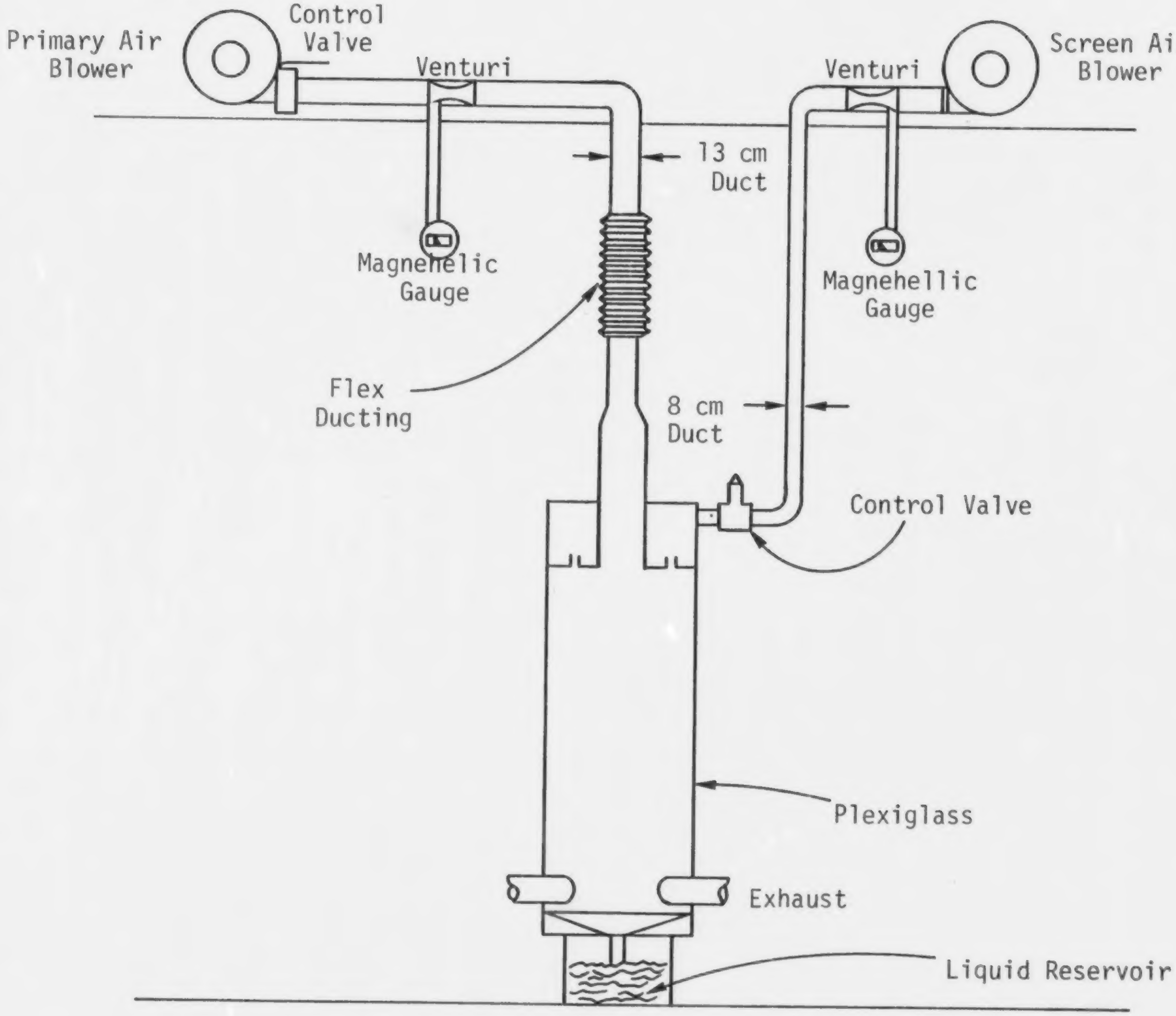
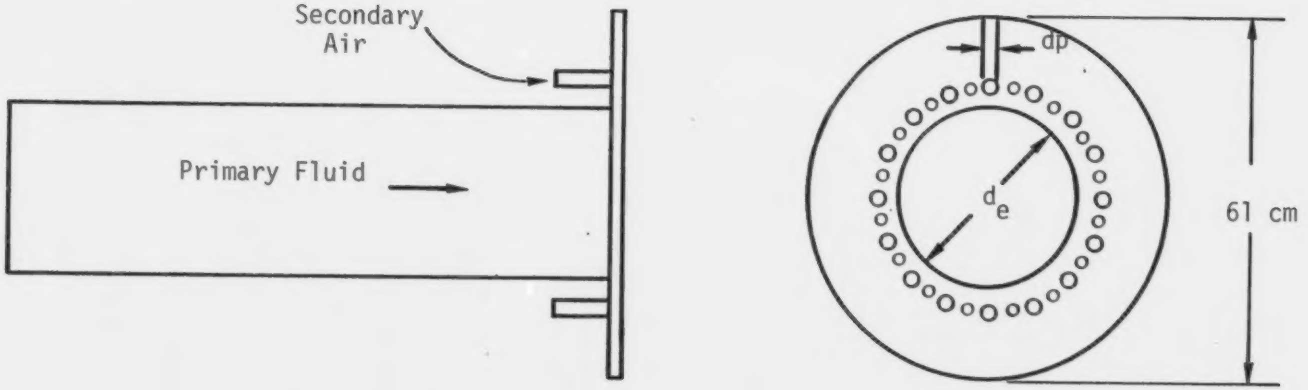

Primary Air Blower
Control Valve
Venturi
Magnehelic Gauge
13 cm Duct
Flex Ducting
Venturi
Screen Air Blower
Magnehellic Gauge
8 cm Duct
Control Valve
Plexiglass
Exhaust
Liquid Reservoir

Figure 2-10. Small spray characterization rig (SSR) used for isothermal flow modeling.

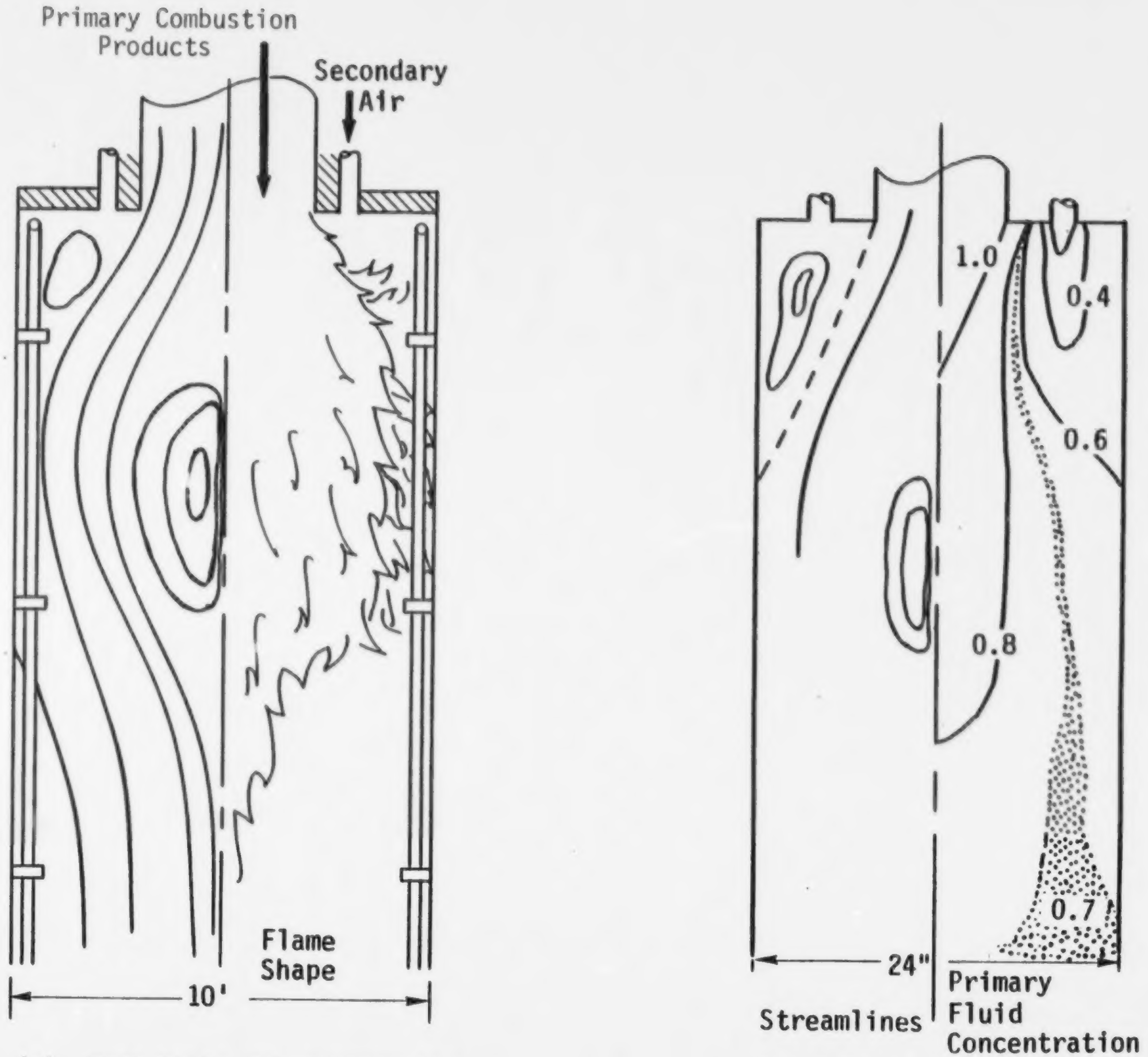
constructed. The burner model hardware is illustrated in Figure 2-11. Air velocity through the secondary air ports was equal to that in the full-scale burner. Two sets of 16 ports were built into the model. One set corresponded to the full-scale baseline configuration and the other set corresponded to a 45 percent reduction in secondary air velocity. Air flow through the primary exit passage was adjusted to yield the same ratio of primary to secondary momentum. Mixing characteristics of the different configurations tested were evaluated by flow visualization techniques using neutral-buoyancy bubbles and slit illumination, and by injection of a tracer into the primary fluid. Bubbles were produced using a commercial bubble generator. The tracer was dilute propane and concentration was measured using an infrared analyzer. All of the equipment used was readily available and the entire test series including data analysis took four days to complete.

The baseline configuration was evaluated first to determine whether the approach to scaling would produce results similar to field observations. Figure 2-12 compares the flame and estimated flow patterns observed in the steamer, under full-load conditions, to the flow patterns and concentration profiles measured in the 1/5 -scale model for the baseline configuration. The flow patterns in the model and full-scale steamer appeared to be similar, characterized by a strong external recirculation zone close to the burner exit, rapid expansion of the primary jet toward the wall, and a lazy central recirculation zone. The point at which the boundary of the primary streams reached the wall in the model corresponded approximately to the point where flame impingement had occurred in the actual steam generator. The apparent spreading angle of the primary jet boundary was approximately 20 degrees (half-angle). The model also indicated that primary fluid was rapidly entrained into the secondary jets and external recirculation zone very close to the burner exit, illustrated by the concentration profiles in Figure 2-12. Concentration of 0.7 represents the completed mixed primary fluid concentration. Overall, the results obtained with the model in the baseline configuration appeared to be representative of conditions observed in the steam generator.


Secondary Air
Primary Fluid
dp
d_e
61 cm

CONFIGURATION	d_e cm	dp cm
Baseline	27.9	1.9
MOD A	22.9	1.9
MOD B	27.9	2.5
MOD C	22.9	2.5

Figure 2-11. Isothermal burner model hardware.


Primary Combustion Products
Secondary Air
Flame Shape
10'
1.0
0.4
0.6
0.8
0.7
24"
Streamlines
Primary Fluid Concentration

(a) Full-Scale Steam Generator

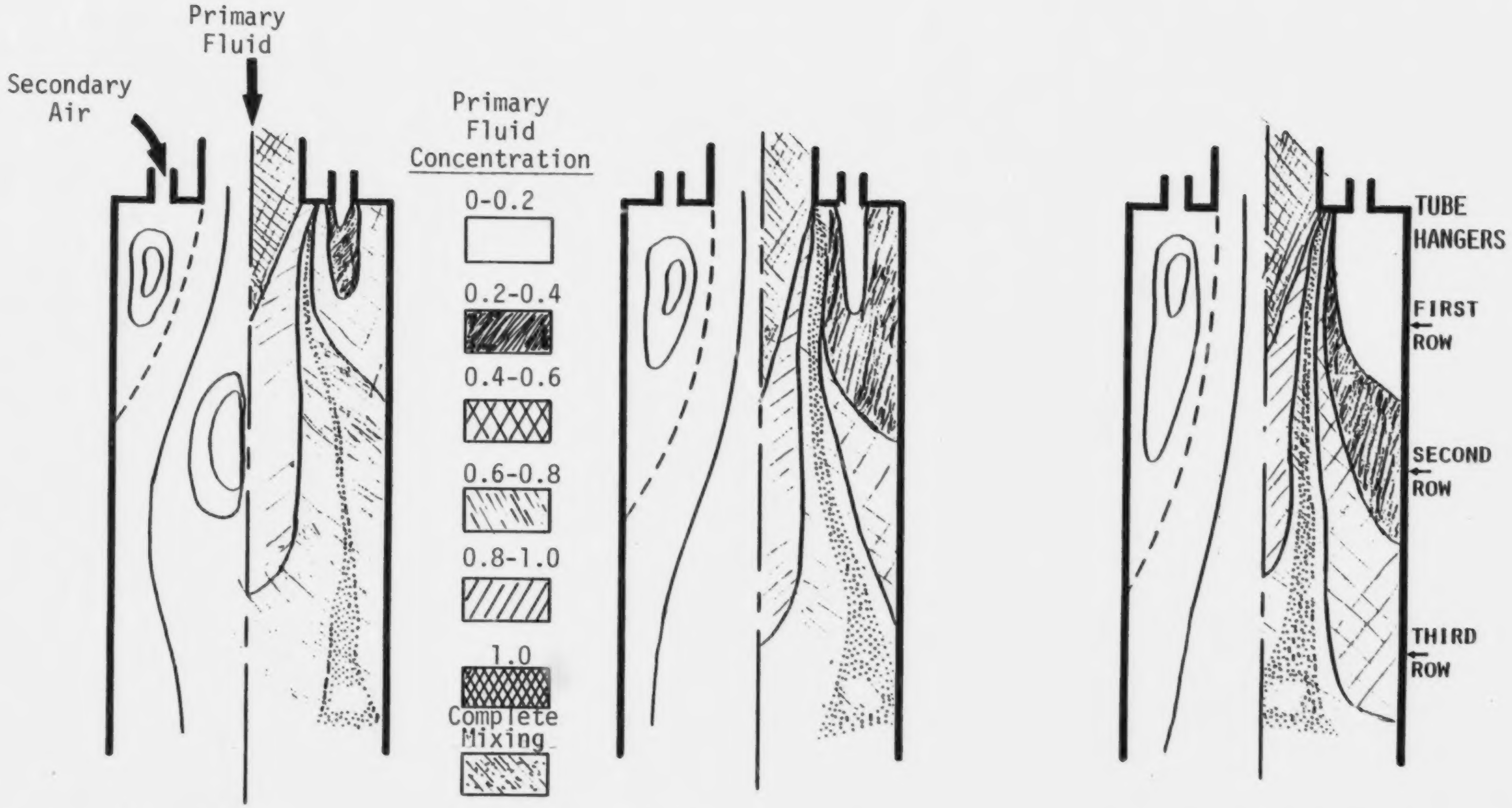
(b) Cold Isothermal Model

Figure 2-12. Comparison of observed flame shape in full-scale steam generator to mixing and flow pattern in cold isothermal model.

Figure 2-13 illustrates model results for two of the modifications which were considered for the full-scale burner. The first modification (2-13b) involved decreasing the first-stage exit diameter. The proposed diameter reduction increased the primary to secondary jet momentum ratio from 0.35 to 0.56. The resulting flow pattern showed that the point at which the primary jet reached the wall was moved 50 percent further downstream, with an apparent spreading angle of 15 degrees. The velocity in the external recirculation zone was somewhat reduced, and the central recirculation zone disappeared entirely. The mixing profiles indicated that the entrainment of primary fluid toward the walls near the burner was significantly reduced. Downstream of the region near the exit both streams appeared to be well mixed, although downstream conditions in the model may not accurately represent full-scale conditions.

A second field modification considered was to remove inserts from the axial secondary air ports thereby enlarging the port area and reducing the momentum of the secondary jets. Figure 2-13c illustrates the flow and mixing patterns obtained with both modifications simulated in the model. This combination resulted in a primary-to secondary jet momentum ratio of 0.99. Reduction of the secondary jet momentum further reduced the apparent spreading angle of the primary fluid boundary to approximately 13 degrees, and significantly reduced the primary fluid concentration at the walls of the model near the burner exit. In spite of the delayed mixing between the streams near the burner, good mixing was still achieved at a distance approximately equivalent to the mid-point of the steam generator, as shown by the region of 0.7 primary fluid concentration.

The results of the isothermal model tests indicated that entrainment of primary combustion products toward the furnace walls close to the burners could be reduced or delayed via modifications to the exit geometry. The rationale for selecting one of the modifications over the others was based on interpretation of the isothermal model results as well as engineering judgement based on experience. Although enlargement of the secondary air jets alone would reduce entrainment significantly, there was concern over whether complete downstream mixing could be achieved at full scale since


Primary Fluid
Secondary Air
Primary Fluid Concentration
0-0.2
0.2-0.4
0.4-0.6
0.6-0.8
0.8-1.0
1.0
Complete Mixing
TUBE HANGERS
FIRST ROW
SECOND ROW
THIRD ROW

(a) baseline

(b) Reduced primary exit diameter

(c) Reduced primary exit diameter and increased secondary air port diameter

Figure 2-13. Flow patterns and tracer concentration for baseline and modified exit geometries.

secondary air jet penetration would be reduced. Reduction of the primary zone exit diameter appeared to offer similar potential for reducing entrainment without adversely affecting downstream mixing. Addtionally, if the result of this modification was not satisfactory, the secondary air ports could be enlarged afterwards. Since this appeared to be a reasonable and cost-effective approach, a temporary sleeve of low-grade refractory bricks was installed in the primary exit to increase the velocity of gases at the first-stage exit by 47 percent. The secondary air ports were not changed. Figure 2-14 illustrates the modification.

The second series of burner shakedown tests showed that the modification had been successful in eliminating the flame impingement problem completely with all 16 secondary air ports wide open. The visible flame was significantly narrower and slightly longer than the original flame. Figure 2-15 compares photographs of the flame taken before and after the modification. The center of the flame appeared clear with no signs of smoke or central recirculation zones. Flame shape was similar to the region in Figure 2-13b bounded by the isopleths of 0.6 to 0.7 primary fluid concentration. Overall flame length was approximately 5.5 to 6.1 meters (between third and fourth row of tube hangers). The "tail" of the flame occasionally licked the steam tubes; however, this was considered minor and did not raise concern over tube or refractory life. Since the flame shape produced by the first modification was considered adequate, no attempts were necessary to further improve flame shape, and burner optimization tests were initiated.

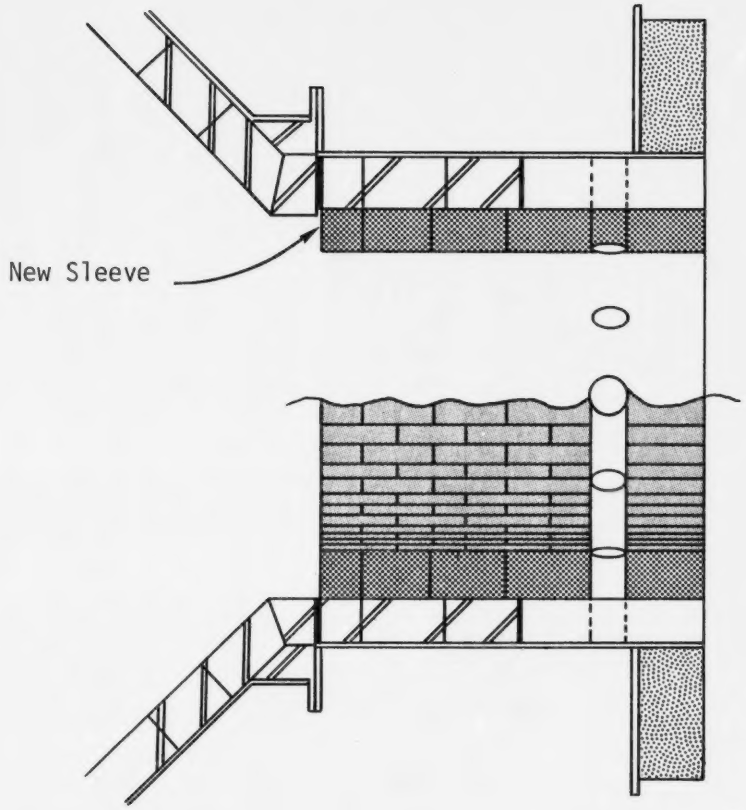
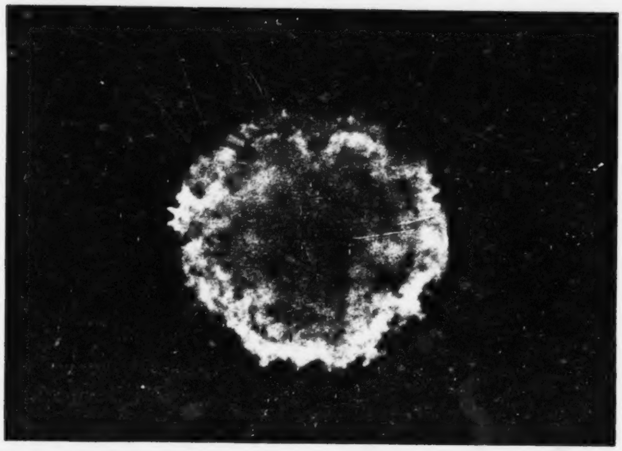
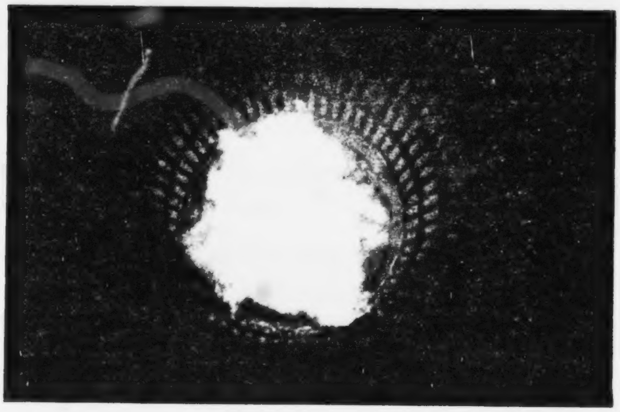


Figure 2-14. Installation of temporary sleeve in first stage exit to increase exit velocity.



Initial Second Stage flame in EOR Steam Generator
Note flame Impingement on wall and evidence
of smoke formation.



Second stage flame in EOR steam generator after
reducing throat diameter . Note tight flame shape
relative to steamer walls.

Figure 2-15. Comparison of flame shape before and after first stage exit modification.

3.0 OPTIMIZATION AND EVALUATION TESTS

The objective of these tests was to determine the optimum burner operating conditions for minimizing NO_x emissions with acceptable CO and smoke emissions. The effect of many of the first-stage parameters (e.g. stoichiometric ratio, atomization, burner stability) had been extensively evaluated and optimized prior to the field installation during the preliminary evaluation tests (4) conducted on the EER Medium Tunnel test furnace. The field optimization tests were focused primarily on optimization of second-stage and operational parameters. The optimum operating conditions were entered into the programmable controller at the end of the optimization tests and a series of long-term evaluation tests were conducted.

A schematic of the continuous monitor system used to measure NO_x, CO, CO_2, O_2 and hydrocarbons is shown in Figure 3-1. SO_2 emissions were not monitored. Exhaust samples were taken from a temporary stack, which was attached to the steam generator exhaust for the purposes of this test, using an uncooled stainless steel sample probe. Sample was transported in a heated teflon sample line to a teflon-lined diaphragm pump. The sample is filtered and dried prior to distribution to the continuous analyzers. Most of the sample is bypassed through the bypass regulator (BPR). The analyzer outputs are read on a multiple-pen strip chart recorder for a permanent data record. The instruments were operated in accordance with EPA Performance Specifications for Continuous Emission Monitors where applicable.

Table 3-1 lists the continuous monitors which were used for the field optimization and evaluation tests. The instruments were calibrated using zero and span gases at approximately 2 hour intervals. Calibration gases were high-purity gases with reported accuracy not exceeding ±5 percent for the 10-199 ppm range gases, ±3 percent for 200-999 ppm range and ±2 percent for the 0.1 to 50 percent range.

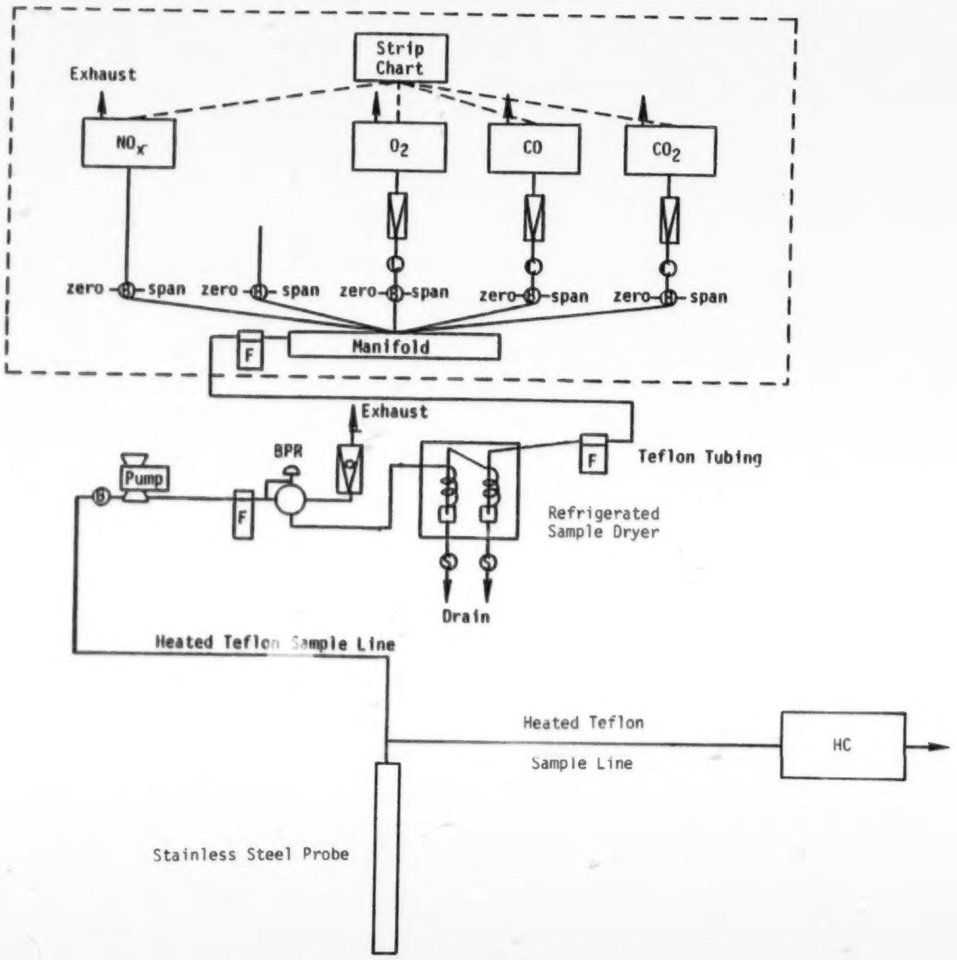

Strip Chart
Exhaust
NO_x
O_2
CO
CO_2
zero
span
zero
span
zero
span
zero
span
zero
span
Manifold
F
Exhaust
BPR
Pump
F
F
Teflon Tubing
Refrigerated Sample Dryer
Drain
Heated Teflon Sample Line
Heated Teflon Sample Line
HC
Stainless Steel Probe

Figure 3-1. Continuous monitor sample acquisition and conditioning system.

TABLE 3-1. CONTINUOUS EMISSION MONITORS USED IN FIELD EVALUATION.

Gas Species	Measurement Principle	Brand	Model No.	Serial No.	Range
O_2	Paramagnetic	Taylor/ Servomex	570A	57001000-187	0-100%
CO_2	Non-dispersive Infrared	Horiba	PIR 2000	108008	0-40%
CO ppm	Non-dispersive Infrared	Horiba	PIR 2000	45738051	0-2500 ppm
NO_x	Chemiluminescent	Thermo-Electron (TECO)	10 AR	10AR-16028-159	0-10,000 ppm
HC	Flame Ionization	Beckman	402	-	0-500 ppm (C_3H_8)

3.1 Burner Optimization

A series of tests was conducted to determine the optimum first-stage stoichiometry and excess O_2 level over the normal operating range. Figure 3-2 shows NO_x, smoke, and CO emissions versus first-stage stoichiometric ratio as a function of excess O_2 level at 15.9 MW_t load. NO_x and CO emissions are corrected to 3 percent O_2. The data show a sharp minimum in NO_x emissions at a first-stage stoichiometric ratio (SR_1) of approximately 0.64. Minimum NO_x concentration of approximately 60 ppm was achieved at the optimum SR_1 and was insensitive to excess O_2 level. CO and smoke emissions were low as SR_1 was decreased; however, below the optimum SR_1 these emissions begin to rise. Smoke emissions below the optimum SR_1 were slightly higher at 2 percent excess O_2 than at 3 percent.

Figure 3-3 shows emissions at approximately 80 percent load (12.6 MW_t). Minimum NO_x emissions were 48 ppm at SR_1 of approximately 0.62, and the NO_x minimum was much broader than at 15.9 MW_t. Minimum NO_x and CO were insensitive to excess O_2 level; however, at 2 percent excess O_2 smoke emissions were considerably higher than at 3 percent of excess O_2. Smoke and CO emissions at the optimum SR_1 are within the program goals.

The emissions results achieved during these tests were consistent with previous tests. NO_x emissions decreased with load primarily due to increased residence time in the fuel-rich first stage. Gas temperature at the first stage exit is relatively insensitive to load, as shown in Figure 3-4. This indicates that the first-stage chamber is nearly adiabatic. Gas temperature at SR_1= 0.64 is approximately 1525^o C. The equilibrium adiabatic temperature at this stoichiometry is approximately 1645^o C. Heat loss from the first stage is primarily due to thermal radiation through the first stage exit to the steam generator radiant furnace. Figure 3-5 compares minimum NO_x emissions from the commercial prototype burner tests in the field and in the test furnace to minimum NO_x emissions from the pilot and bench scale experiments (4). NO_x emissions are shown versus calculated plug flow residence time in the first stage and are at the optimum SR_1 for each experiment. NO_x decreases with increasing residence time due to the decay of

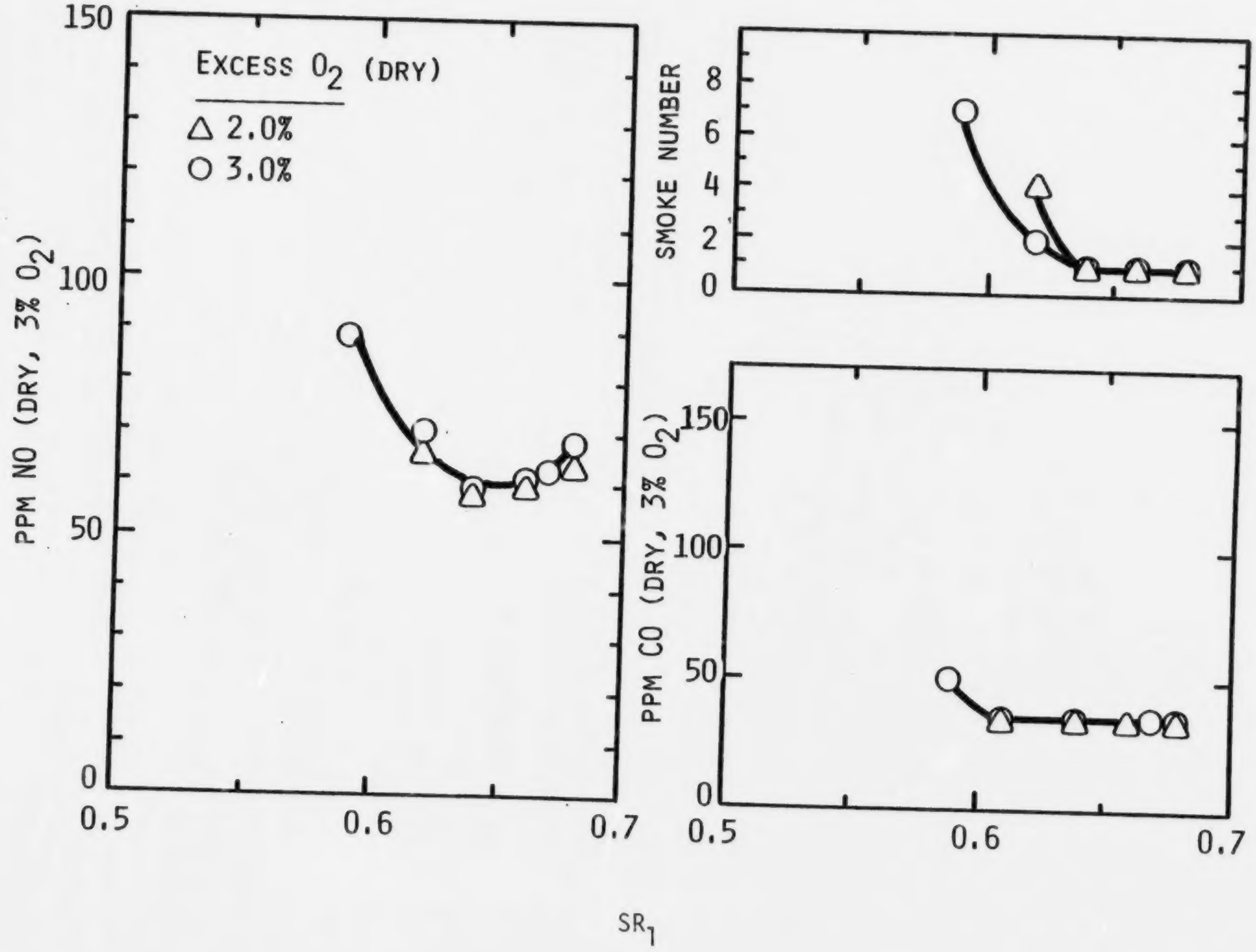


Figure 3-2. NO_x, CO, and smoke emissions at 15.9 MW_{th} load.

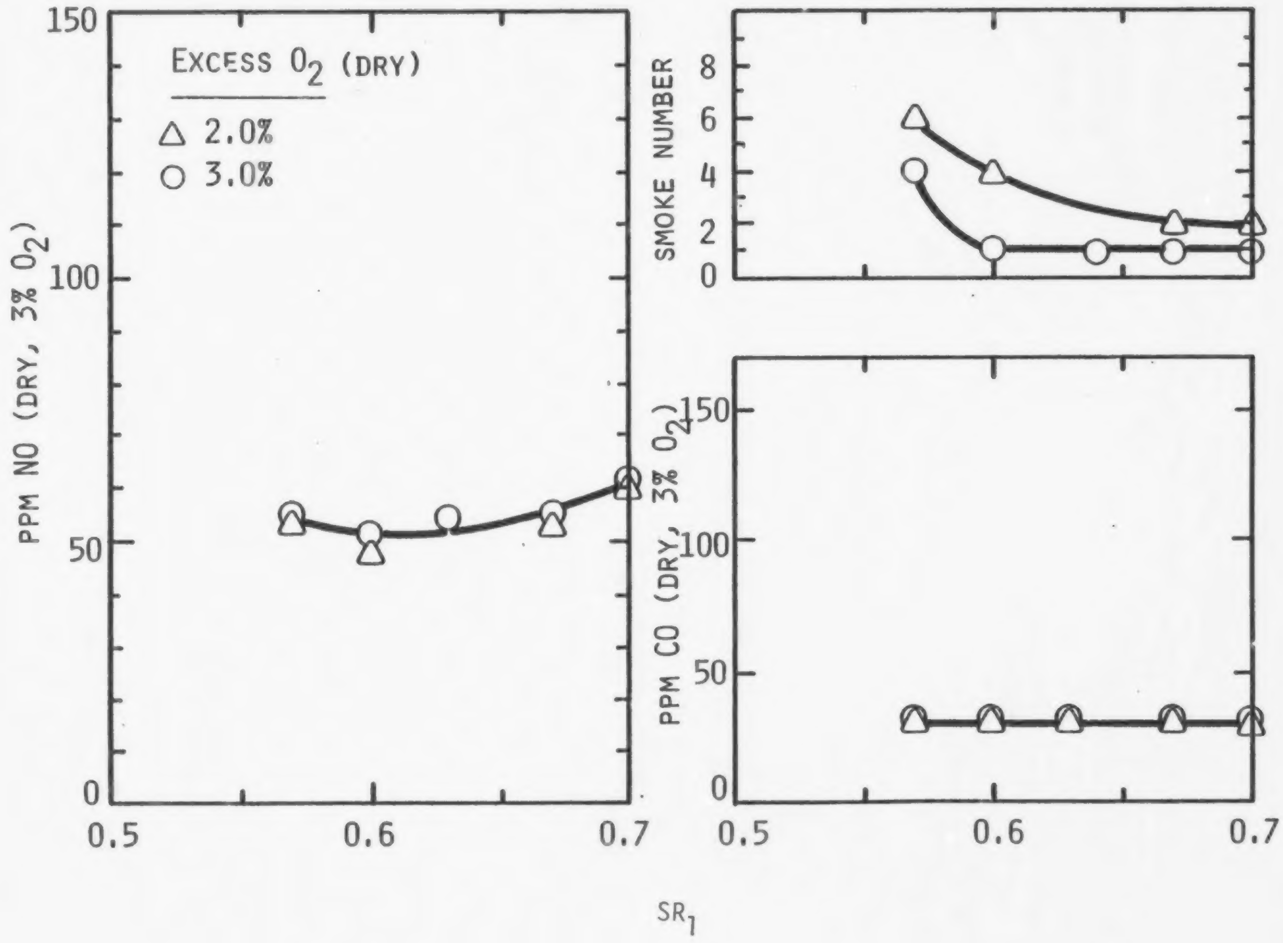


Figure 3-3. NO_x, CO, and smoke emissions at 12.6 MW_{th} load.

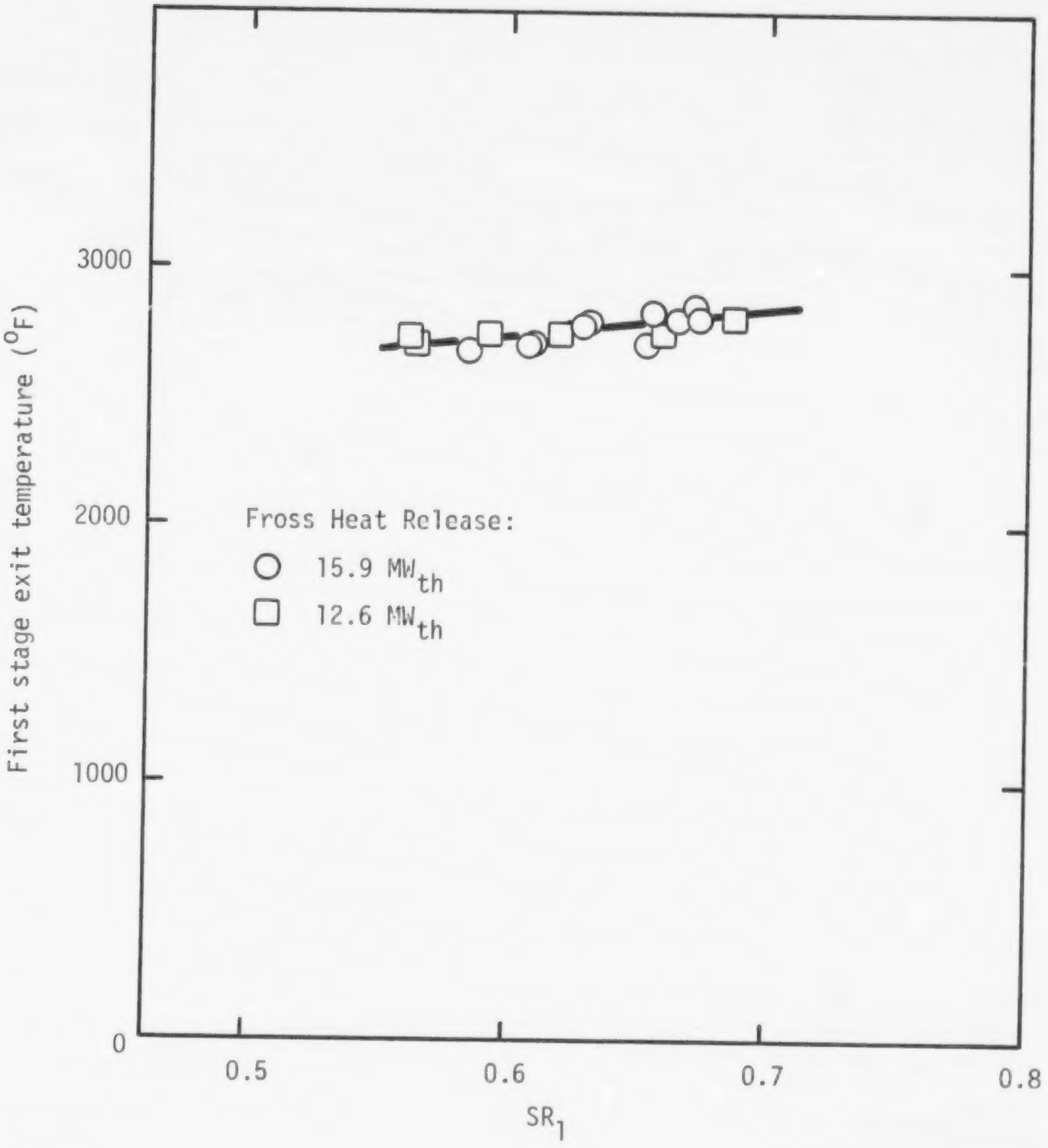


Figure 3-4. Gas temperature at first stage exit.

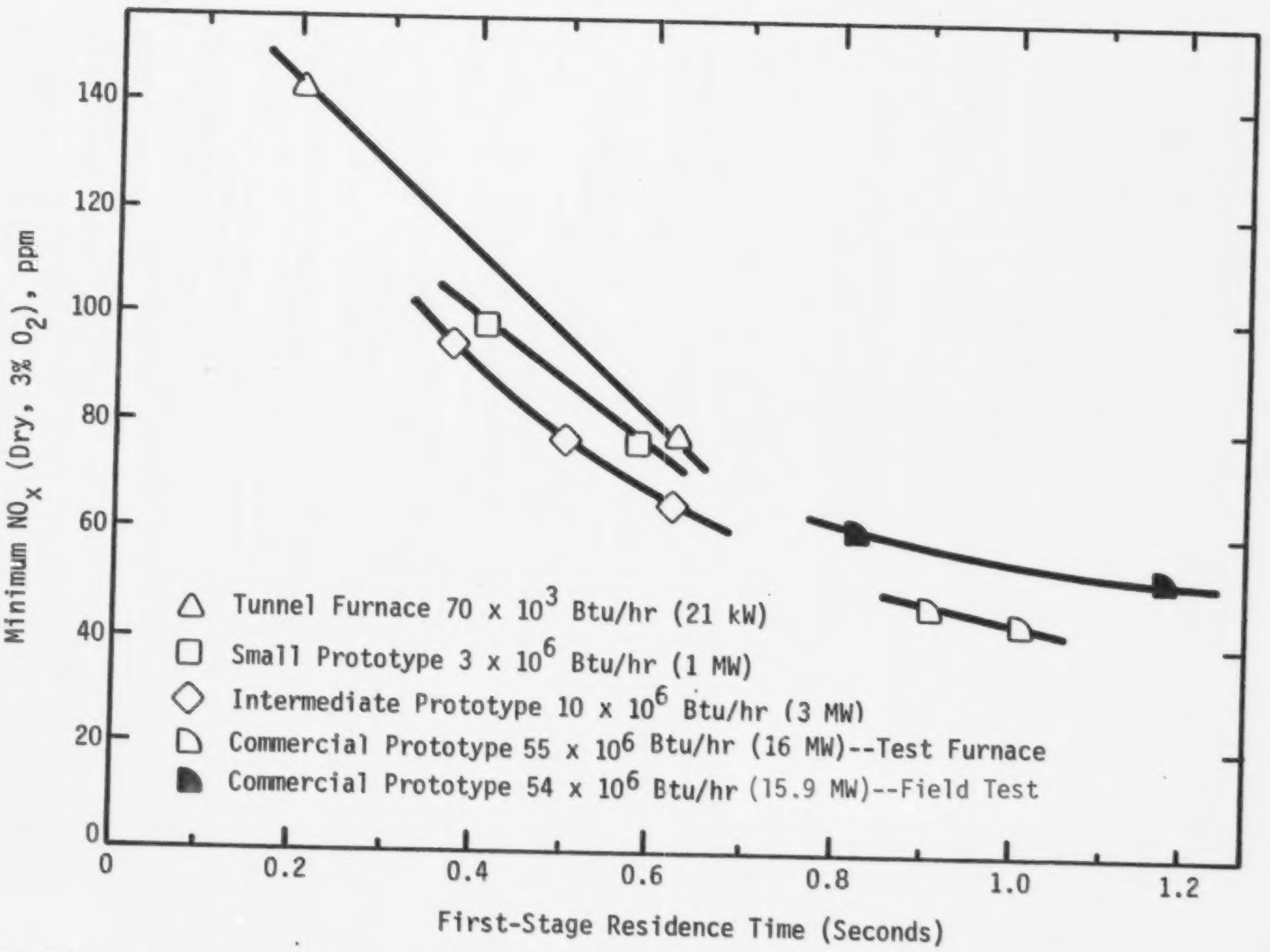


Figure 3-5. Comparison of NO_x emissions from bench-, pilot-, and full-scale prototype burner designs.

fixed nitrogen species (eg. NO, HCN,NH_3) in the fuel-rich first stage to N_2. All the data appear to correlate rather well with residence time over a range in scale of approximately 800:1. NO_x emissions from the bench and pilot scale burners decrease slightly with increasing scale. This is most likely due to decreased heat loss from the first stage as scale is increased leading to higher first-stage temperatures. Data from the Commercial Prototype (16 MW_t) evaluation in the test furnace appear to agree well with the 3 MW_t pilot-scale prototype results. NO_x emissions in the field were slightly higher than in the test furnace. This is most likely caused by (a) increased first-stage exit velocity, and (b) differences in second-stage mixing and thermal environment.

Pilot scale tests at 3 MW_t had shown that NO_x emissions increased by approximately 32 percent (from 72 to 95 ppm) when first stage exit velocity was doubled. Assuming the effects of furnace environments are negligible, NO_x emissions from the full scale burner increased by 27 percent (from 43 to 55 ppm at 1 second residence time) when first stage exit velocity was increased by a factor of 1.5.

4.0 LONG TERM EVALUATION

After the optimum burner operation conditions were established, they were programmed into the programmable controller. The burner was subjected to a series of detailed evaluation tests including continuous emissions monitoring over a thirty-day period and measurement of particulate and organic hydrocarbon emissions. The thirty-day emissions evaluation measurements were performed by Acurex Corporation under EPA Contract 68-02-3188.

Table 4-1 lists the optimized burner settings for full load which were maintained during the detailed evaluation tests. NO_x emissions typically ranged between 65 and 70 ppm at these settings. The optimum SR_1 for these burner conditions was approximately 0.63 to 0.64; however, the control system was programmed to maintain an SR_1 of approximately 0.65 to ensure low smoke emissions in the event of a control system failure.

4.1 Measurements

Measurements of flue-gas composition during the thirty-day continuous monitoring test included O_2, CO_2, NO_x, CO and SO_2. In addition to the continuous monitors, detailed emission characterization measurements included:

- Semi-volatile and non-volatile organic compounds;
- Particulate mass emission;
- Particulate size distribution;
- HCN, NH_3;
- SO_2, SO_3.

The accuracy of the continuous analyzers was verified by following the procedures outlined in EPA Performance Specifications 2 and 3 pertaining to the accuracy of continuous emission monitors. This verification involved measurement of NO_x, CO_2 and O_2 by EPA reference methods.

TABLE 4-1. OPTIMUM BURNER CONDITIONS DURING DETAILED EMISSIONS EVALUATION.

PARAMETER	VALUE
First-Stage	
SR_1	0.65
Register Setting	CW-5*
Atomizing Steam Pressure (kPa)	965
Oil Pressure (kPa)	827
Oil Temperature (^oC)	127
Primary Air Temperature (^oC)	230
Atomizer Spray Angle (degrees)	90
Second-Stage	
Excess O_2 (%)	2.8 (dry)
No. of Air Ports Open	16

* CW = clockwise rotation;
5 = register setting (10=full open; 0=full closed)

Table 4-2 compares flue-gas composition measurements determined by EPA reference methods to the reading from the continuous analyzers. The data shown in the table represent an abbreviated verification of the accuracy of the continuous emission monitors in the EER test trailer. Six grab samples were taken from the stack and analyzed by an independent laboratory (see Appendix B). The O_2, CO_2, and NO_x analyzers were all within 20 percent accuracy. EPA Performance Specifications 2 and 3 require that relative accuracy be less than 20 percent. True relative accuracy was not meaningful in this test since the number of samples is too small to be statistically significant. However, it is clear that the absolute difference between the continuous analyzer readings and reference method values was small, and, therefore, within acceptable limits.

Table 4-3 shows results from the Acurex NO_x monitor certification test. Nine groups of three samples were obtained during the first series of certification tests and three groups of three samples were obtained during the second series. Relative accuracy for these tests was also within acceptable limits according to EPA Performance Specifications.

4.2 Detailed Emissions Characterization

4.2.1 Particulate Emissions

Particulate emissions were measured by both EER and Acurex during the long term evaluation. Table 4-4 lists the results from all particulate emissions tests. Three different methods were used to evaluate particulate mass loading: EPA Method 5; Anderson cascade impactor; and the EPA Source Assessment Sampling System (SASS), which was modified slightly for these tests by removing the cyclone train. All of the measurements determined by EER were taken at the end of the burner optimization trials prior to the initiation of the thirty-day test. Acurex performed all measurements which were taken during the thirty-day test period. Figure 4-1 shows the Method 5 sampling system. Particulate matter is withdrawn isokineticly from the stack and collected on a glass fiber filter maintained at a temperature in the range of 120° C (250° F). All particulate mass including any material which

TABLE 4-2. CONTINUOUS MONITORS (FIELD OPTIMIZATION)

SPECIES	METHOD	AVERAGE 6 SAMPLES)	CONTINUOUS MONITORS	RELATIVE ACCURACY
NO_x	EPA METHOD 7	73 PPM	68 PPM	6.8%
CO_2	ORSAT (EPA METHOD)	13.1%	13.4%	2.3%
CO	G C	1 PPM	30 PPM	---
O_2	ORSAT (EPA METHOD)	3.3%	2.8%	15.2%

TABLE 4-3. CONTINUOUS NO_x MONITOR (CONTINUOUS MONITORING TEST - ACUREX)

NO_x CERTIFICATION	EPA METHOD 7	NO_x MONITOR	AVERAGE DIFFERENCE	RELATIVE ACCURACY
FIRST SERIES (9 SAMPLES)	64 PPM	69 PPM	11 PPM	15%
SECOND SERIES (3 SAMPLES)	65 PPM	69 PPM	9 PPM	19%

TABLE 4-4. PARTICULATE EMISSIONS

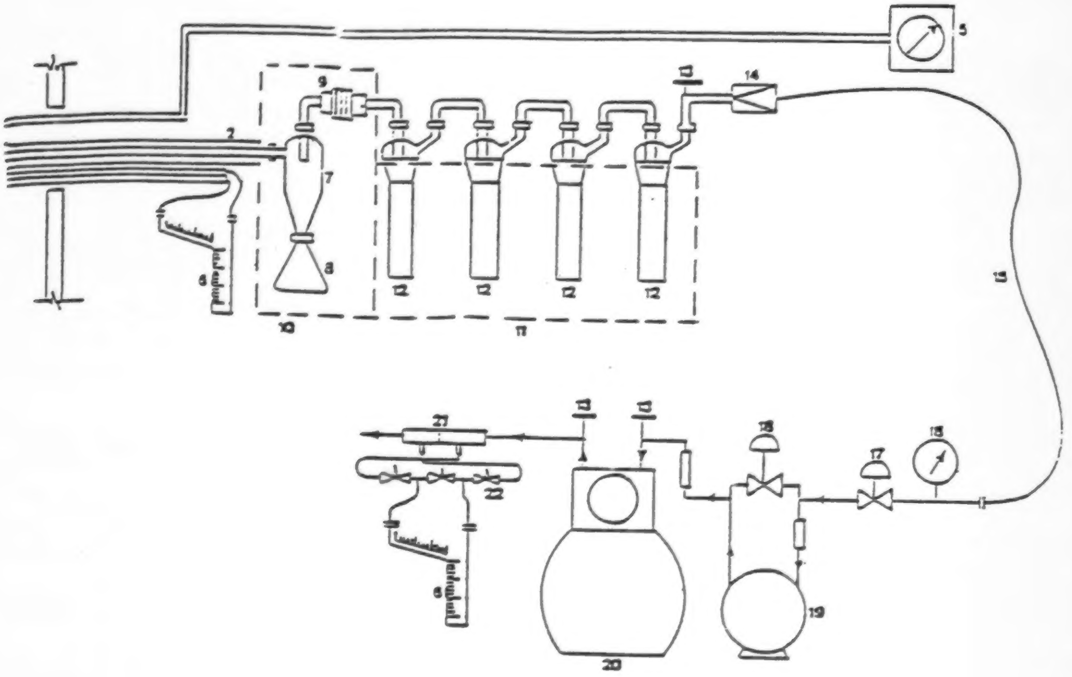
QUALITY ASSURANCE

PARTICULATE EMISSIONS

METHOD	PARTICULATES (GR/DSCF) SOLIDS	CONDENSIBLE	TOTAL
EPA METHOD 5	0.015	—	—
	0.020	—	—
	0.028*	0.037*	0.065*
	0.056**	0.006*	0.062*
ANDERSON CASCADE IMPACTORS	0.015	—	—
	0.013*	—	—
	0.017*	—	—
MODIFIED SASS	0.016	—	—
	0.010	—	—
	0.011*	—	—
AVERAGE	.016	.022	.064
STANDARD DEVIATION	.005	.022	.002

* DETERMINED DURING 30 DAY CONTINUOUS MONITORING PERIOD

** OUTLIER - EXCLUDED FROM AVERAGE


5
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16
22
6
19
20

LEGEND

1. NOZZLE
2. PROBE
3. PITOT
4. THERMOCOUPLE
5. PYROMETER
6. INCLINE MANOMETER
7. CYCLONE
8. FLASK
9. FILTER ASSEMBLY
10. FILTER BOX
11. IMPINGER ICEBATH
12. IMPINGERS
13. THERMOMETER
14. CHECK VALVE
15. UMBILICAL CORD
16. VACUUM GAUGE
17. COARSE FLOW ADJUST VALVE
18. FINE FLOW ADJUST VALVE
19. VACUUM PUMP
20. DRY TEST METER
21. ORIFICE TUBE
22. SOLENOID VALVES

Figure 4-1. Method 5 sampling System

condenses at or above the filter temperature is collected on the glass fiber filter and determined gravimetrically after the filter is dried. The EPA method does not require condensible particulate collected in the impingers to be included in total emissions; however, the local Kern County Air Pollution Control District does require condensible particulate to be included in the total emission. Average particulate emission based on the Method 5 results was .048 grams per dry standard cubic meter (.021 grains per dry standard cubic foot). When condensible particulate was included in the total, the average was approximately 0.145 grams per dry standard cubic meter (0.064 grains per dry standard cubic foot).

Total particulate emissions measured by cascade impactor and SASS were very consistent with the Method 5 results, within the absolute accuracy of the methods at these low particulate loadings. Average particulate emissions for the impactor runs was 0.034 grams per dry standard cubic meter (g/dscm), and was .028 g/dscm (.012 gr/dscf) for the SASS runs. The average of all solid particulate measurements was 0.037 g/dscm (0.016 gr/dscf) with the exclusion of one outlier. Average total particulate including condensible particulate was 0.146 g/dscm (0.064 gr/dscf).

The level of particulate emissions from the host steam generator equipped with the low NO_x burner system is within the range typically measured for conventional steam generators without scrubbers and, for those generators equipped with scrubbers, at the inlet to the scrubber. Field data indicate that the total emission level at the scrubber inlet of five generators ranged from .048 g/dscm to 0.206 g/dscm. Average particulate emissions excluding the condensible fraction was 0.059 g/dscm (0.026 gr/dscf). Average particulate emissions including the condensible fraction were 0.119 g/dscm (0.052 gr/dscf).

Particulate size distribution in the 0.7 to 10 micron size range was also measured using Cascade Impactors. Sub-micron particulate size distribution was not determined. Figure 4-2 shows the size distribution determined from one run prior to the thirty-day continuous monitoring test and from two runs during the thirty-day test. The results are generally in

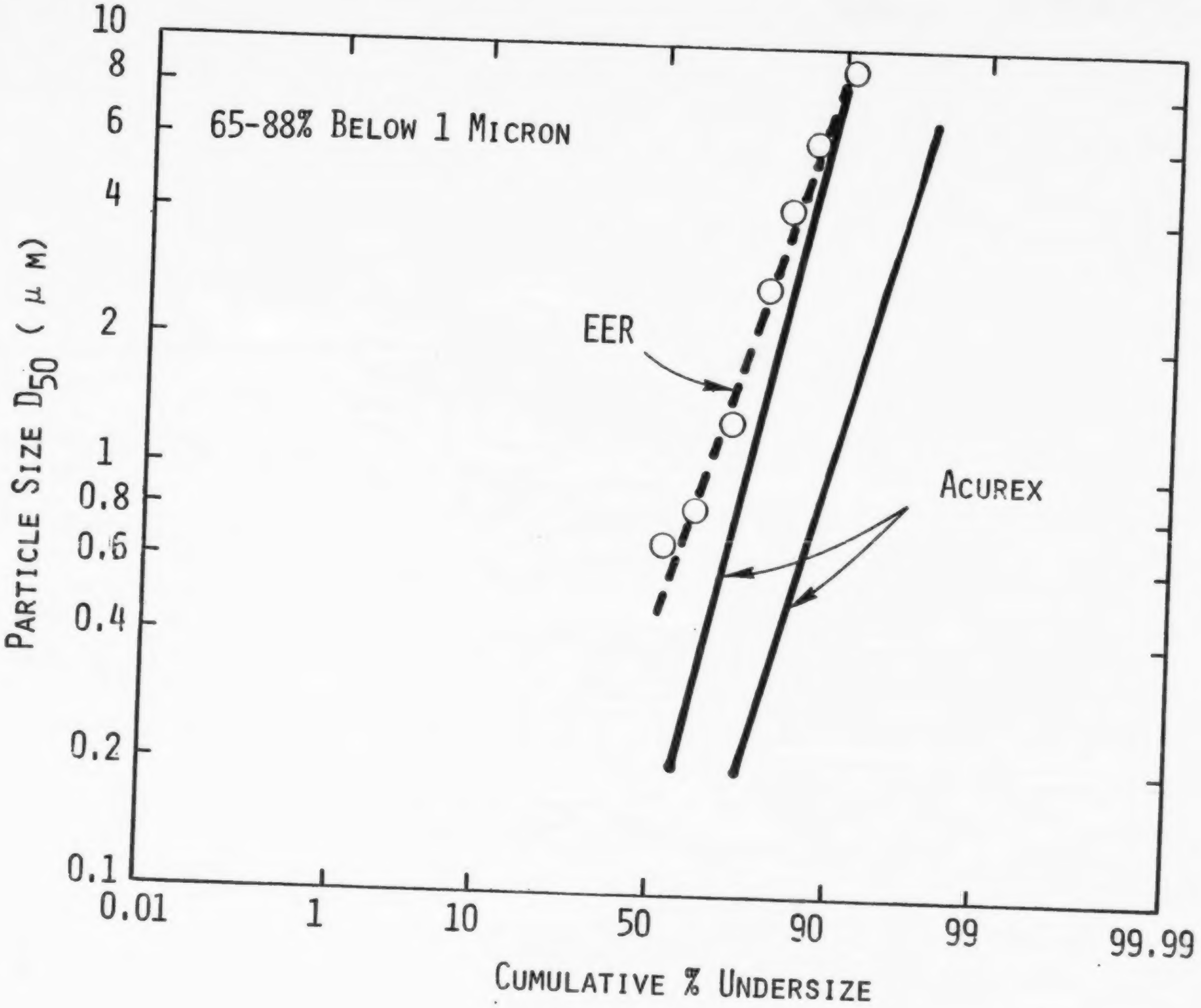


Figure 4-2. Particulate Emissions - Anderson Cascade Impactors

good agreement and indicate that 65 to 88 percent of the solid particulate collected in the impactors was below 1 micron. These results are also in good agreement with other data which typically showed that peak particulate emissions are in the 1 to 3 micron size range.

4.2.2 HCN and NH_3 Emissions

HCN and NH_3 are of interest because they exist in significant concentrations (100 to 500 ppm) at the exit of the fuel-rich prechamber. Normally these species are consumed very rapidly in the second stage flame. HCN and NH_3 were determined using the sampling train shown in Figure 4-3. HCN and NH_3 are absorbed in solution in a series of impinger bottles and concentration is subsequently determined by specific ion electrode. NH_3 concentration in the steamer flue gas was less than or equal to 1 ppm. HCN concentration was below the detectability limits for the method, approximately 1 ppm. It is clear that these species are effectively destroyed in the second-stage flame.

4.2.3 SO_2 and SO_3 Emissions

SO_2 and H_2SO_4/SO_3 concentrations were determined during the thirty-day test using EPA Method 8 and controlled condensation methods. Table 4-5 and 4-6 summarize the results from these two series of tests. Total SO_x emissions averaged approximately 635 ppm, which corresponds approximately to the level expected for 100 percent conversion of sulfur in the fuel oil (615 ppm at 3 percent O_2). The level of SO_3 measured by EPA Method 8 was much lower than the level determined by the controlled condensation method. In EPA Method 8 the sample is drawn through a series of impingers which contain different solutions. The first impinger contains 80 percent isopropyl alcohol, which collects SO_3. Sulfur dioxide is also determined with this method and is collected in the second and third impingers in an absorbing solution of hydrogen peroxide. A filter is usually placed between the first and second impingers to prevent carry-over of SO_3 (as acid mist). In the controlled condensation method the sample is drawn through a heated quartz filter to remove particulate and then through a condenser coil maintained at

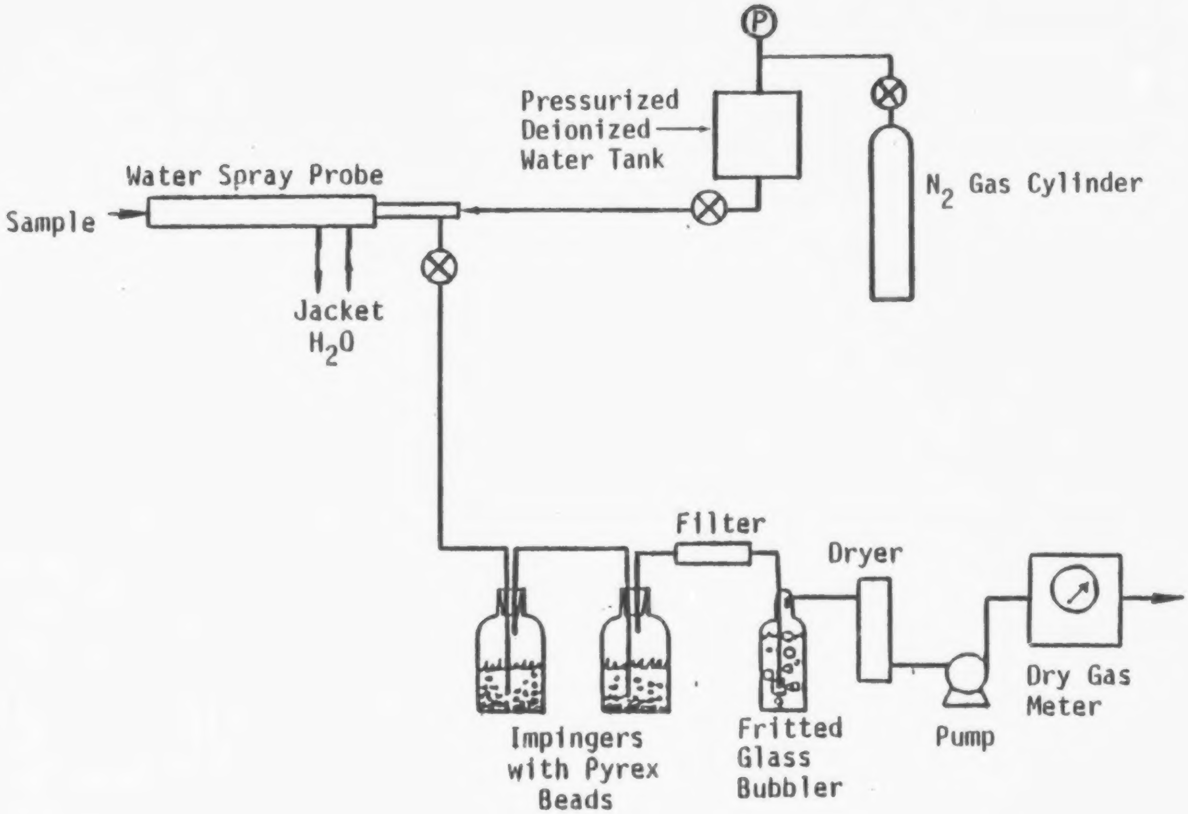

Pressurized
Deionized
Water Tank
N$_2$ Gas Cylinder
Water Spray Probe
Sample
Jacket
H$_2$O
Filter
Dryer
Impingers
with Pyrex
Beads
Fritted
Glass
Bubbler
Pump
Dry Gas
Meter

Figure 4-3. HCN/NH_3 sampling system.

TABLE 4-5. SULFUR SPECIES EMISSIONS MEASURED BY EPA METHOD 8

	Run 1	Run 2
Method 8		
SO_2, ppm dry, 3 percent O_2	619	593
SO_3, ppm dry, 3 percent O_2	12.9	4.4
Continuous monitor		
SO_2, ppm dry, 3 percent O_2	557	574

TABLE 4-6. SULFUR SPECIES EMISSIONS MEASURED BY CONTROLLED CONDENSATION METHOD

	Run 1	Run 2
Controlled Condensation System		
(2/23/84)		
SO_2, ppm dry	602	611
SO_3, ppm dry	47	51
Continuous Monitors		
SO_2, ppm dry	642	--[a]
O_2, percent dry	4.4	--

[a]--: monitors inoperative

a constant temperature below the sulfuric acid dewpoint, but above the water dewpoint (generally 140° F to 160° F) to collect SO_3. After sampling, the condensation coil is washed with isopropyl alcohol. Both methods utilized the barium-thorin titration technique to determine SO_3 concentration.

The accuracy of EPA Method 8 is questionable because of the potential for oxidation or absorption of a small amount of SO_2 in the isopropyl alcohol, resulting in a high SO_3 determination. Also, the SO_2 may be oxidized by trace impurities in the alcohol, by trace materials in the particulate that are not removed by the glass wool filter upstream of the impingers, or by condensible compounds that collect in the impinger. Since the SO_3 concentration is usually only a small percentage of the SO_2 concentration, it is necessary to collect only a small percentage of the SO_2 in the isopropyl alcohol to give erroneous SO_3 results. For these reasons, the controlled condensation technique is usually considered more accurate in the determination of SO_3. However, it can be seen that the results obtained during the thirty-day test appear to go in the opposite direction to that expected.

SO_3 concentration determined using the controlled condensation technique typically ranges from 10 to 30 ppm for steam generators burning Kern County fuels. SO_3 concentration for oil-fired boilers normally ranges from 5 to 10 percent of the SO_2 concentration. The slightly higher SO_3 emission produced by the Commercial Prototype burner may be related to differences in the heat distribution pattern in the steam generator radiant section. SO_3 emissions are affected by the flue-gas temperature, by the time/temperature history of the flue gases in the convective section of the boiler, and by excess O_2 level. Although the level of SO_3 in the flue gases appears to be high compared to normal steam generators, it is within the range normally expected for oil-fired boilers. No data on SO_3 emissions from the host steam generator prior to the low NO_x burner retrofit are currently available.

4.2.4 Organic Emissions

The emission of organic compounds is of concern because of their potential carcinogenic activity. Semi-volatile and non-volatile organic compounds were determined by both EER and Acurex. Acurex also determined volatile organic emissions during the thirty-day test period.

Table 4-7 presents emissions of volatile organic species determined by gas chromatographic analysis of flue gas grab samples. Only toluene, benzene and ethyl benzene were detected in the stack gases. Benzene concentration was 60 micrograms per dry standard cubic meter or 18 parts per billion. Concentrations of toluene and ethyl benzene were below 1 part per billion. The concentration of 29 other organic pollutants was determined to be less than one microgram per dry standard cubic meter.

Table 4-8 presents data for total semi-volatile and non volatile organic emissions. Organic emissions were determined using EPA Level 1 analysis procedures. The EPA Source Assessment Sampling System (SASS) was used to make the measurements. The particulate filter, XAD-2 resin, and the condensate in the SASS were solvent extracted with methylene chloride and subsequently analyzed. As shown in Table 4-8, semi-volatile and non-volatile organic emissions were very low. The total organic emission level was below 0.3 milligrams per dry standard cubic meter.

Although no federal standard for emissions of organic species has been established, certain organic species have been determined to have adverse health effects and are maintained on EPA's list of priority pollutants. Table 4-9 lists the emissions of various compounds detected in the sample extracts. Low levels of phenol and naphthalene were detected in each run. The presence of phthalates most probably originates from impurities in the solvents used to wash down the sampling equipment.

There are currently no known organic emission data from conventional steam generators with which to compare these results. Castaldini et al. (8) have conducted tests on a steam generator equipped with a commercial low NO_x

TABLE 4-7. VOLATILE ORGANIC SPECIES EMISSIONS: EOR STEAM GENERATOR TESTS

Compound[a]	Stack Gas Concentration[b]				
	Run 1 (μg/dscm)	Run 2 (μg/dscm)	Run 3 (μg/dscm)	Average (μg/dscm)	(ppb)
Benzene	128	42	9	60	18
Toluene	6.3	1.1	2.3	3.2	0.83
Ethylbenzene	3.2	<1	<1	1.7	0.39

[a] Chloromethane, bromomethane, vinyl chloride, chloroethane, methylene chloride, chloroform, 1,1-dichloroethylene, 1,1-dichloroethane, 1,2-dichloroethane, t-1,2-dichloroethylene, 1,1,1-trichloroethane, trichloroethylene, carbon tetrachloride, dichlorobromomethane, 1,2-dichloropropane, t-1,3-dichloropropene, chlorodibromomethane, 1,1,2-trichloroethane, c-1,3-dichloropropene, 2-chloroethyl vinyl ether, bromoform, 1,1,2,2-tetrachloroethane, tetrachloroethylene, chlorobenzene, xylenes, allyl chloride, ethylene oxide, propylene oxide, and 2-nitropropane were also analyzed for and not detected above a blank corrected detection limit of 1.0 μg/dscm

[b] Mean (field, trip, and laboratory) blank corrected

TABLE 4-8. ORGANIC COMPOUNDS - TOTAL ORGANIC EMISSIONS (ACUREX)

Sample	Total Semivolatile Organics (TCO)	Total Nonvolatile Organics (GRAV)	Total Organics	
			mg	mg/dscm
Filter particulate	--[a]	<3	<3	<0.1
XAD-2 + OMC extract[b]	3.8	3	7	0.3
Total flue gas	3.8	3	7	0.3

[a] TCO not performed; sample collected at high temperature
[b] Field blank corrected

TABLE 4-9. ORGANIC COMPOUNDS - PRIORITY POLLUTANTS

	ACUREX			EER		
COMPOUND	RUN 1 μG	RUN 2 μG	AVERAGE RATE μG/DSCM	RUN 3 μG	RUN 4 μG	AVERAGE RATE μG/DSCM
Phenol	20	10	0.7	144	190	6.53
Napthalene	40	20	1.4	3.1	2.1	0.11
Dimethylphthalate	100	60	3.6	-	-	-
Di-N-Butylphthalate	-	-	-	61	56	2.38
Bis(2-Ethylhexyl)Phthalate	-	-	-	86	135	4.24
Butylbenzylphthalate	-	-	-	5.5	5.5	0.23
Di-N-Octylphthalate	-	-	-	10	7.2	0.36
Phenanthrene	-	-	-	2.5	2.8	0.11
Total	160	90	5.7	312	398.6	13.96

burner system designed by Mitsubishi Heavy Industries. Organic emissions reported for this test are shown in Table 4-10. Significant quantities of volatile organic (C1-C6) species were measured. Semi-volatile organic emissions were low but non-volatile organics were also high. Total organic emissions were approximately 11.1 milligrams per dry standard cubic meter. These high levels are indicative of the high smoke emissions observed under the test condition which was evaluated. Priority pollutants were also identified in this study. Total concentration for the three polycyclic organic compounds and nine other species which were detected was 79 micrograms per dry standard cubic meter.

4.3 Thirty-Day Continuous Monitoring Test

Continuous monitoring of NO_x, CO_2, CO, SO_2, and O_2 in the steam generator exhaust was performed by Acurex during the thirty-day test. Complete results were not available at the time this report was prepared. Figures 4-4, 4-5 and 4-6 present emissions data for a 9-day sampling period. Figure 4-4 shows that flue-gas oxygen concentration averages approximately 2.8 percent (dry-basis) during this period, in agreement with the control system set point. Excursions to as high as 3.5 percent were observed on the continuous monitors during part of this period. This was attributed to drift in the control system which was subsequently rectified. O_2 level remained between approximately 2.5 and 3.0 percent for the remainder of the test period.

Figure 4-5 shows NO_x and CO emissions for the same period. NO_x emissions averaged approximately 69 ppm during the 9-day period and CO emissions remained below 50 ppm. NO_x emissions typically ranged between 56 ppm and 75 ppm (corrected to 3 percent O_2) and varied cyclicly within each day. This is a result of drift in the fuel-flow meter output as the result of ambient temperature changes. Output from the fuel flow meter is used by the programmable controller to control primary air-flow rate and thereby SR_1. The temperature drift problem resulted in excursions of NO_x to as high as 84 ppm.

TABLE 4-10. TOTAL ORGANIC EMISSIONS: EOR STEAMER TESTS

Organic Category	mg/dscm	ng/J
Volatile organics analyzed in the field by gas chromatography		
C_1	0.2	0.7
C_2	0	0
C_3	8.4	29.8
C_4	2.2	7.8
C_5	0	0
C_6	0	0
Total C_1-C_6	10.8	38.3
Semivolatile organics analyzed by TCO		
Filter	--	
XAD-2	<0.004	<0.014
Total C_7-C_{16}	<0.004	<0.014
Nonvolatile organics analyzed by gravimetry		
Filter	0.3	1.1
XAD-2	<0.1	<0.35
Total C_{16+}	0.3	1.1
Total organics	11.1	39.4

Species	Filter	XAD-2 Run 1	XAD-2 Run 2	Total
			μg/dscm	
Phenol	0.22	0.96	1.4	1.4
Naphthalene	0.19	<0.04	<0.04	0.19
Phenanthrene	0.30	<0.04	<0.04	0.30
Pyrene	0.11	<0.04	<0.04	0.11
Benzothiazole	3.2	—	—	3.2
Fluoren-9-one	20	—	—	20
Ethylcarbazole	13	—	—	13
Terphenyl	5.2	—	—	5.2
Benzofurandione	--	0.37	0.52	0.44
Benzoic acid	--	35	33	34
Dichlorodibenzosulfone	--	0.48	0.55	0.52
Ethyl benzoate	--	0.37	0.44	0.40

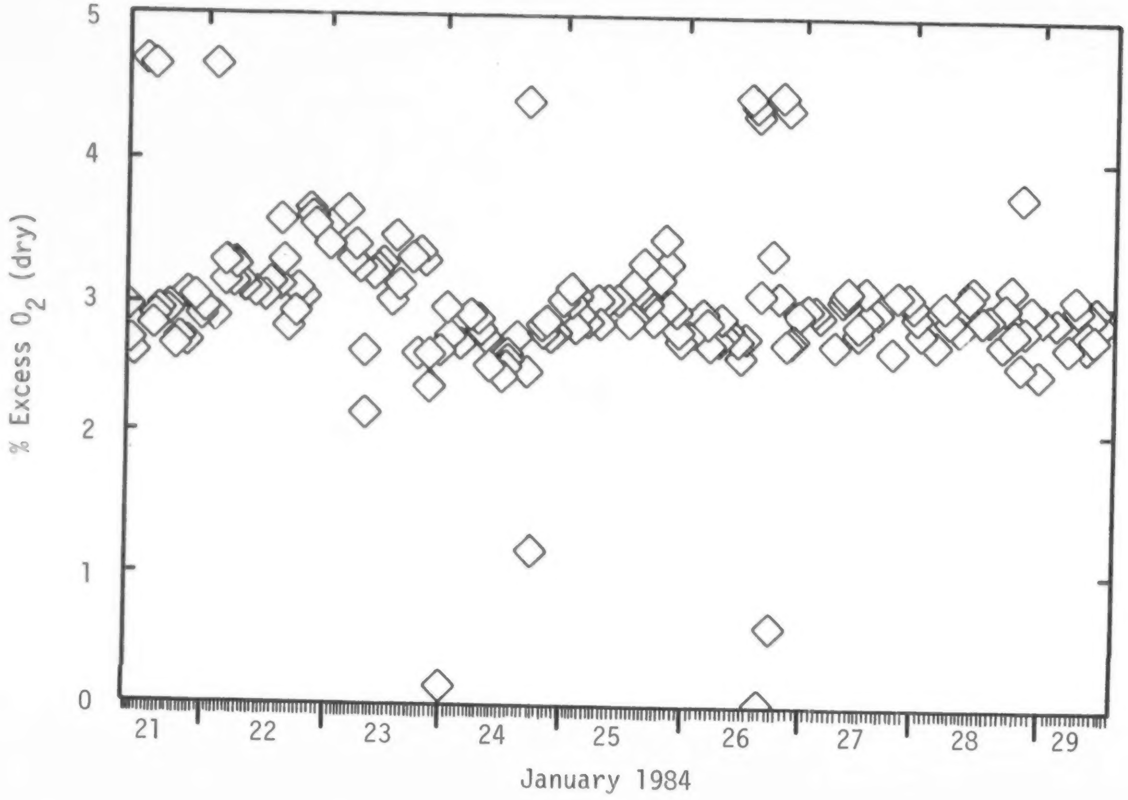


Figure 4-4. Excess O_2 concentration during 30-day test.

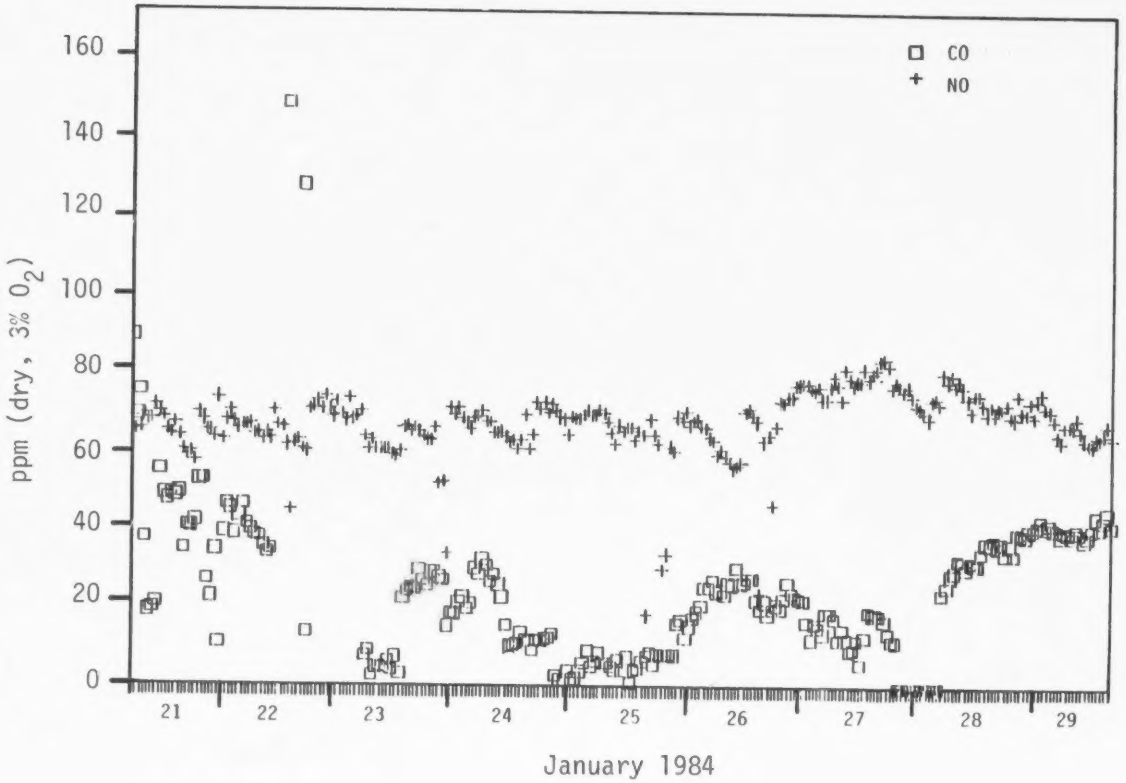


Figure 4-5. NO_x and CO emissions during 30-day test.

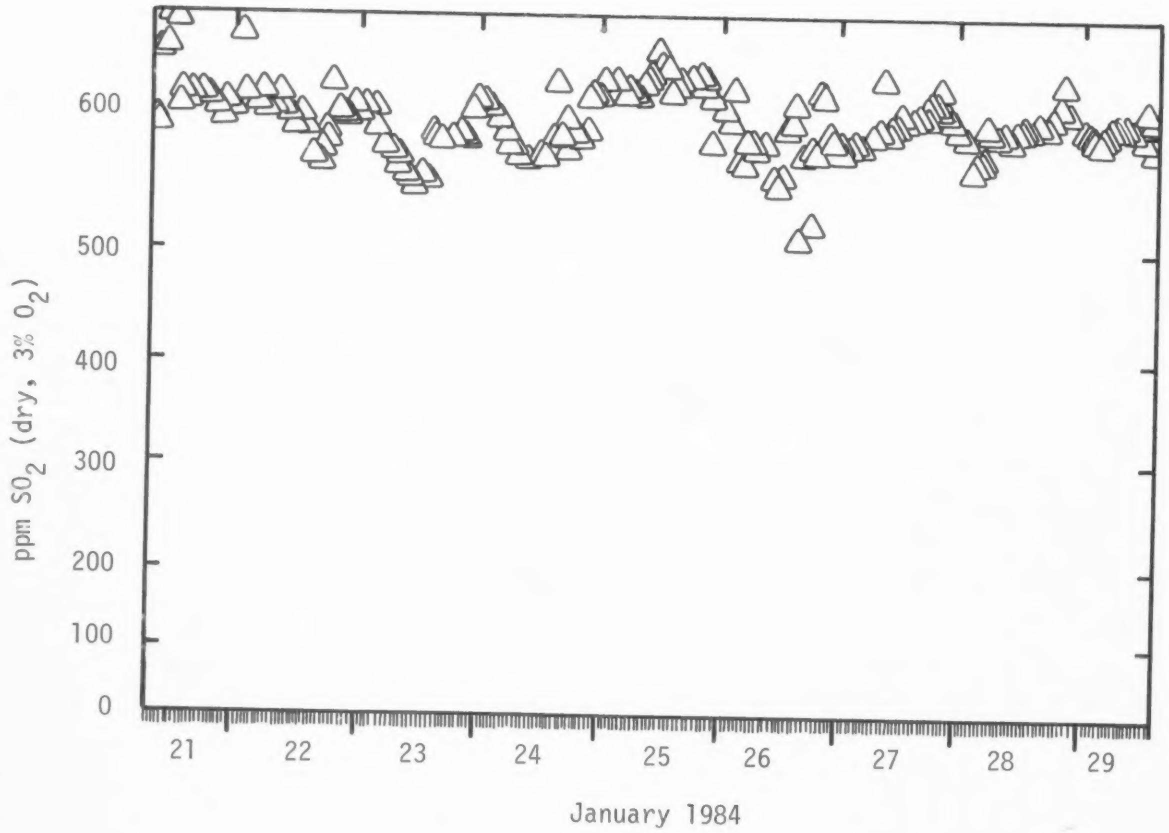


Figure 4-6. SO_2 emissions during 30-day test.

Figure 4-6 presents SO_x emissions measured during this same test period. SO_2 concentration ranged between approximately 520 and 650 ppm (corrected to 3 percent O_2) and averaged approximately 580 ppm. These levels are in the range expected based on 100 percent conversion of the sulfur in the fuel.

Preliminary evaluation of results obtained over the entire thirty-day performance test period indicate that the results shown in Figures 4-4 to 4-6 are typical of the entire period. All information on emissions during the thirty-day test which was available at the time this report was prepared are presented in Appendix D.

4.4 Steam Generator Efficiency

The thermal efficiency of boilers is generally determined by either the ASME heat-loss method or input-output method. The input-output method requires accurate measurement of fuel flow rate, fuel heating value, and steam flow rate, pressure, and temperature. The heat-loss method requires measurement of O_2, CO_2, CO, and moisture in the flue gas, flue gas temperature, as well as fuel ultimate analysis and heating value. Table 4-11 shows the measurements and typical errors associated with each measurement required for both methods. The heat-loss method is usually considered to be more accurate than the input-output method because of the smaller errors involved with each of the measurements.

In TEOR steam generators, steam quality must also be measured to determine input-output efficiency. The error typically associated with this measurement can be very significant. The most widely used methods for determining steam quality are:

- Sodium tracer and flame photometry;
- Electrical conductivity;
- Throttling calorimeter; and
- Gravimetric methods.

TABLE 4-11. EFFICIENCY DETERMINATION: MEASUREMENTS AND ASSOCIATED ERRORS (REF. ASME PTC 4).

MEASUREMENT	MEASUREMENT ERROR PERCENT	ERROR IN CALCULATED STEAM GENERATOR EFFICIENCY, PERCENT
(1) Weigh tanks (calibrated scales)	±0.10	±0.10
(2) Volumetric tanks (calibrated)	±0.25	±0.25
(3) Calibrated flow nozzle or orifice including manometer	±0.35	±0.35
(4) Calibrated flow nozzle or orifice including recorder	±0.55	±0.55
(5) Coal scales-batch or dump (calibrated)	±0.25	±0.25
(6) Uncalibrated flow nozzle or orifice including manometer	±1.25	±1.25
(7) Uncalibrated flow nozzle or orifice including recorder	±1.60	±1.60
(8) Fuel heating value (coal)	±0.50	±0.50
(gas and oil)	±0.35	±0.35
(9) Reheatflow (based on heat balance calculations)	±0.60	±0.10
(10) Superheater outlet temperature (calibrated measuring device)	±0.25	±0.15
(11) Superheater outlet pressure (calibrated measuring device)	±1.00	±0.00
(12) Reheater inlet and outlet temperature (calibrated measuring device)	±0.25	±0.10
(13) Reheater inlet and outlet pressure (calibrated measuring device)	±0.50	±0.00
(14) Feedwater temperature (calibrated measuring device)	±0.25	±0.10
HEAT-LOSS METHOD		
(1) Heating value (coal)	±0.50	±0.03
(gas and oil)	±0.35	±0.02
(2) Orsat analysis	±3.00	±0.30
(3) Exit gas temperature (calibrated measuring device)	±0.50	±0.02
(4) Inlet air temperature (calibrated measuring device)	±0.50	±0.00
(5) Ultimate analysis of coal (carbon)	±1.00	±0.10
(hydrogen)	±1.00	±0.10
(6) Fuel moisture	±1.00	±0.00

The throttling calorimeter determines steam quality directly, but is only accurate for relatively high steam quality (above 90 percent). The other methods actually measure dissolved solids concentration in the steam and feed water. Steam quality is determined from solids concentration according to the following formula:

$$\%\ \text{Steam Quality} = 100\left(1 - \frac{\text{ppm solids in steam}}{\text{ppm solids in feedwater}}\right)$$

It is common to determine steam quality in the oil fields by measurement of electrical conductivity. Solids content is directly proportional to conductivity, which can be easily measured. The major errors associated with this method are due to dissolved gases in the steam, especially CO_2 and NH_3, which produce high electrical conductivity leading to erroneously high solids concentration determination. Field measurements must also be corrected for temperature of the sample.

The thermal efficiency of the host steam generator prior to the retrofit of the Commercial Prototype burner was determined by the host site operators using the input-output method. Efficiency determined in this manner is routinely used by the host to schedule steamer maintenance for cleaning of the convective economizer section from ash and sulfate fouling. Thermal efficiency for several months prior to the burner retrofit are given in Table 4-12. Thermal efficiency based on the input-output method ranged from 80 to 93 percent and averaged 85.3 percent. Efficiency determined by heat-loss method was also estimated based on information supplied by host site personnel. Heat-loss efficiency for each of these tests was based on typical fuel analysis, measured O_2 concentration (dry basis), and flue gas exhaust temperatures measured using an existing control thermocouple located in the steam generator exhaust. Unmeasured and radiation losses were neglected. Heat-loss efficiency ranged from 83.6 to 87.8 percent, and averaged 85.5 percent. It can be seen that although the average efficiency is approximately equal by both methods, scatter is about 3 times greater for the input-output method. Table 4-13 presents efficiency for several conditions during the burner optimization trials and detailed emissions characterization, prior to the thirty-day test. Average efficiency based on

TABLE 4-12. THERMAL EFFICIENCY OF HOST STEAM GENERATOR PRIOR TO RETROFIT OF COMMERCIAL PROTOTYPE BURNER.

Date	Heat Release (a) (MW_t)	Excess O_2 (%, wet basis)	Steam (b) Quality (%)	Thermal (c) Efficiency (%)	Flue Gas Exhaust Temperature (^{0} C)	Thermal (d) Efficiency (%)
9/2/82	15.7	3.7	66	80	177	87.1
11/22/82	18.4	3.1	82	82	259	83.6
12/6/82	16.6	2.8	68	80	160	87.8
11/4/83	15.7	2.8	75	86	232	84.8
8/16/83	12.1	2.3	81	91	215	85.1
5/19/83	16.7	2.9	73	93	232	84.8
avg.	15.9	2.9	74	85.3	213	85.5

(a) per barrel of crude oil
(b) by electrical conductivity
(c) input-output--determined by host
(d) heat loss--determined by EER according to ASME method. Estimates were used where measurements were not taken.

TABLE 4-13. THERMAL EFFICIENCY OF HOST STEAM GENERATOR WITH EER/EPA LOW-NO_x BURNER.

Date	Time	Heat (a) Release (MW_t)	Excess O_2 (%, dry)	Steam Quality (b) (%)	Thermal Efficiency (c) (%)	Flue Gas Exhaust Temperature (° C)	Thermal Efficiency (d) (%)
1/5/84	1225	15.7	2.9	83	103	196	86.4
1/7/84	--	15.7	2.9	73	87	204	86.4
1/7/84	0725	15.7	2.9	83	97	210	86.2
1/9/84	0750	15.7	3.0	84	95	234	85.4

(a) per barrel of oil
(b) by electrical conductivity-by host site
(c) input/output method
(d) heat loss method-neglecting unmeasured and radiation losses.

the heat-loss method was 86.1 percent. Data were not available for the thirty-day test to determine efficiency trends over a longer period. The data shown in Table 4-13 were taken for relatively steady state conditions during the detailed emissions characterization. Input-output efficiency was typically much higher than heat-loss efficiency. In one case, input-output efficiency exceeded 100 percent. This is most likely due to error in the measurement of steam quality. Except for the single data point on 1-7-84, where quality was 73 percent, all steam quality numbers in the table were "field" values, uncorrected for temperature or dissolved gases.

Comparison of thermal efficiency (based on the heat-loss method) before and after the burner retrofit shows that there was no adverse impact on steam generator efficiency associated with the Commercial Prototype burner. This is not surprising since estimated shell heat losses from the prechamber are small (less than 0.2 percent) and since combustion efficiency was greater than 99 percent. A complete assessment of the long term impact of the burner on steam generator efficiency will be obtained in future tests over an extended period.

4.5 Mechanical Performance

At the completion of the thirty-day test, the burner was inspected to determine the mechanical condition of each of the major components. The burner had undergone over 1600 hours of testing and cycled 20 times, 7 of which were unforeseen shut-downs including 3 power outages. Additionally the burner had survived the rigors of being transported 480 kilometers from the EER test site in El Toro, California, to the host steam generator site in Kern County, California, near Bakersfield.

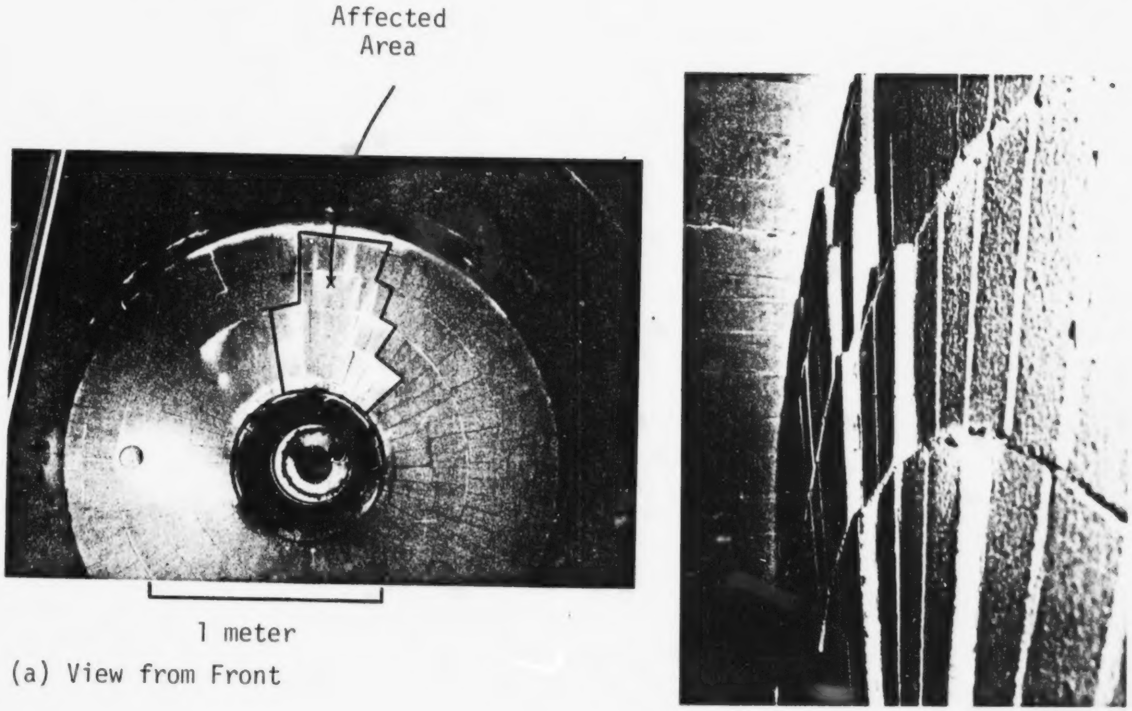
4.5.1 Refractory Condition

The overall mechanical condition of the burner was very good at completion of the thirty-day test. One of the key areas of concern was how well the refractory lining had survived the thirty-day test and especially the numerous thermal cycles. Inspection of the refractory lining showed that all refractory including the primary burner throat was in excellent shape, except for a small section of brick on the front wall and the temporary sleeve in the first stage exit.

A section of brick in the front wall of the burner appeared to have shifted and was working its way out of the lining. Figure 4-7a shows the affected area, which covers a section of the wall from about 11 o'clock to 2 o'clock. As seen in Figure 4-7b, the ends of several of these bricks extended approximately 1.3 to 2.0 centimeters from the normal plane of the front wall. This most likely occurred during heat-up and cool-down of the lining when differential thermal expansion allows the upper section of the front wall to go into tension. Experience with this type of progressive movement of refractory brick work suggests that there is a chance of eventual lining failure if a brick manages to work itself completely out of lining. However, it is difficult to estimate how probable this failure is and whether it would occur within a time scale on the order of months or years.

The sleeve of refractory brick which was installed in the primary exit area to increase first stage exit velocity was constructed of medium grade refractory brick containing 50 to 70 percent alumina. This material was selected because of its immediate availability as well as to reduce the cost of the flame optimization tests. Because these materials were not expected to survive the high temperature and reducing atmosphere in the first stage, it was planned to replace the sleeve if the modification was a success. The condition of the sleeve at the end of the thirty-day test was very poor. Many parts of the sleeve had deteriorated substantially, and a few places were in danger of complete collapse. The remainder of the brick and rammed refractory near the first stage exit was in excellent condition.

Certain areas of the refractory in the first stage chamber showed varying degrees of ash penetration. The most severely affected areas of the burner were located on the cylindrical walls near the front end of the burner and on the front wall. Ash penetration was as deep as 1.5 millimeters in these areas. Two small areas (approximately 5 by 10 centimeters) showed signs of shallow surface fouling; however, this was determined by the host


Affected
Area
1 meter

(a) View from Front

(b) View from Side

Figure 4-7. View of front wall showing shift in section of refractory.

site operators and by the refractory manufacturer representative to be insignificant. The back half of the chamber including the convergent section and the exit section did not appear to show signs of significant ash deposits. At the current rate of ash penetration and spalling, liner lifetime should be well in excess of 7 years.

Overall condition of the refractory was excellent considering the severe duty experienced during the field evaluation tests. Representatives of the refractory manufacturer and their construction subsidiary were consulted to determine whether the front wall of the burner needed to be repaired or replaced. In their opinion, the chances of a complete and sudden failure of the front wall, due to the displacement of a few bricks, was unlikely; however, they did recommend that the progress of these bricks be monitored during periodic shut-downs. They also recommended that the sleeve in the primary zone exit be replaced before further operation of the burner.

4.5.2 Control System

The burner control system successfully maintained emissions of criteria pollutants within the program goals for the duration of thirty-day test without operator supervision. This proves the practicality of maintaining minimum NO_x emissions through control of first stage stoichiometry. Minor excursions in NO_x occurred due to drift in the fuel-flow meter output as a result of changes in ambient temperature. The output of the fuel flow meter is utilized by a programmable controller to maintain constant first stage stoichiometry. The control system maintains a constant ratio of primary air to fuel flow above approximately 11 MW_t. This maintains the first stage stoichiometric ratio at the optimum level for minimum NO_x emissions. Secondary airflow is adjusted to maintain a pre-set level of excess oxygen. Primary airflow remains constant below approximately 11 MW_t to ensure adequate airflow for shell cooling. Since the controller causes primary airflow to follow fuel flow, the temperature drift in the fuel flow meter output resulted in variations in first stage stoichiometry and, therefore, variations in NO_x level. The flow meter manufacturer was consulted and it was learned that they had since developed a meter up-grade to substantially reduce the temperature drift problem. This was the only apparant deficiency in the control system.

4.5.3 Shell Temperature

The temperature of the inner burner shell was monitored to determine thermal performance during steady state and transient operation. Figure 4-8 shows the location of the 21 thermocouples which were installed on the inner shell of the recuperative air channel. The burner is designed to transfer heat across the refractory lining and inner steel shell to the primary air. The outer burner shell is insulated and maintains outer skin temperature below approximately 60° C. Four thermocouples were selected for input to the high burner temperature cut-out control system. These are also indicated on the figure. These thermocouples were selected based on strategic shell location where potential refractory failure was believed most likely to occur, as well as representativeness of mean shell temperatures.

During the preliminary evaluation on the EER test furnace (4) tests were conducted to determine the temperature profile along the inner shell as a function of burner operating conditions. Figure 4-9 shows the inner shell temperature profile under full load conditions with $SR_1=0.6$. Average shell temperature rises from 60° C near the primary air inlet at the rear of the recuperative shell to 225° C near the front burner wall. Figure 4-10 shows the highest measured shell temperature as a function of burner load ranging from 25 to 100 percent. This test was initiated at steady-state full-load operating conditions. Load was then decreased step-wise, maintaining constant first-stage stoichiometry. Temperatures were allowed to stabilize before making another change. It can be seen in the figure that shell temperature rises with turn-down at constant primary air to fuel ratio because of decreased air-flow through the recuperative shell. Steady state conditions were not determined for low load operating conditions. Since there is some heat transfer from the first stage through the primary exit to the downstream furnace, it is likely that peak shell temperatures under steady state reduced load conditions may be somewhat cooler than shown on the figure; however, these temperatures are representative of near-worst case

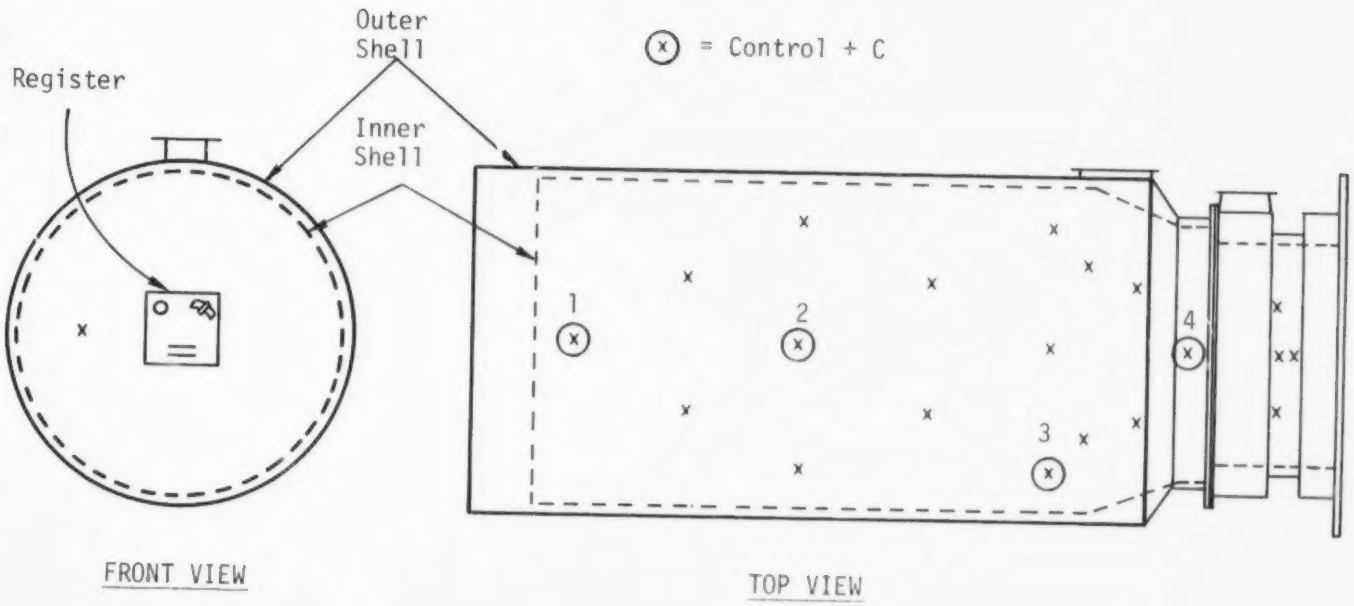

Register
Outer Shell
Inner Shell
(x) = Control + C
1
2
3
4
FRONT VIEW
TOP VIEW

Figure 4-8. Location of inner shell temperature thermocouples on Commercial Prototype burner (location of thermocouples marked by "x").

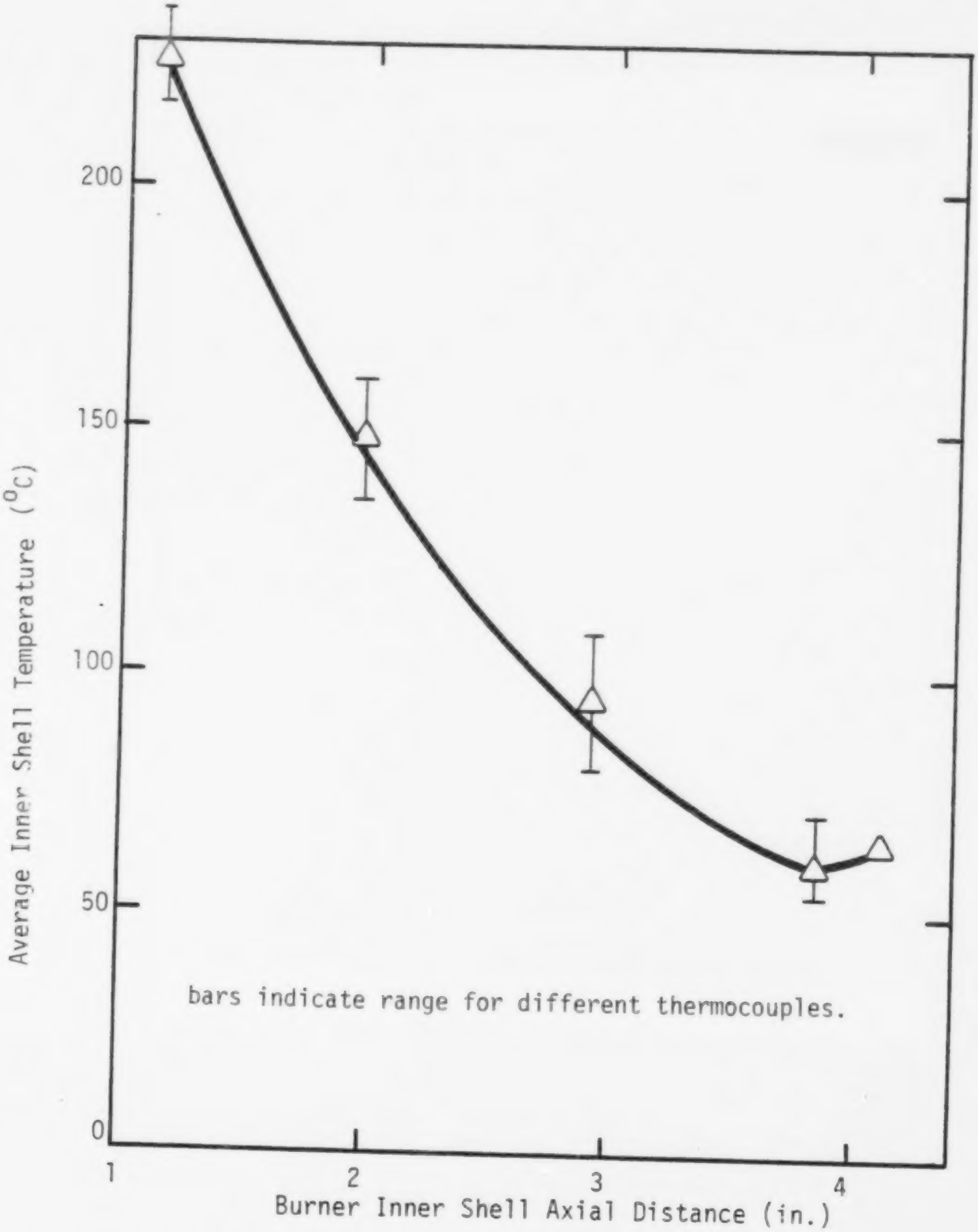


Figure 4-9. Typical inner shell (top half) temperature profiles for full-load operating conditions ($SR_1 \sim 0.6$).

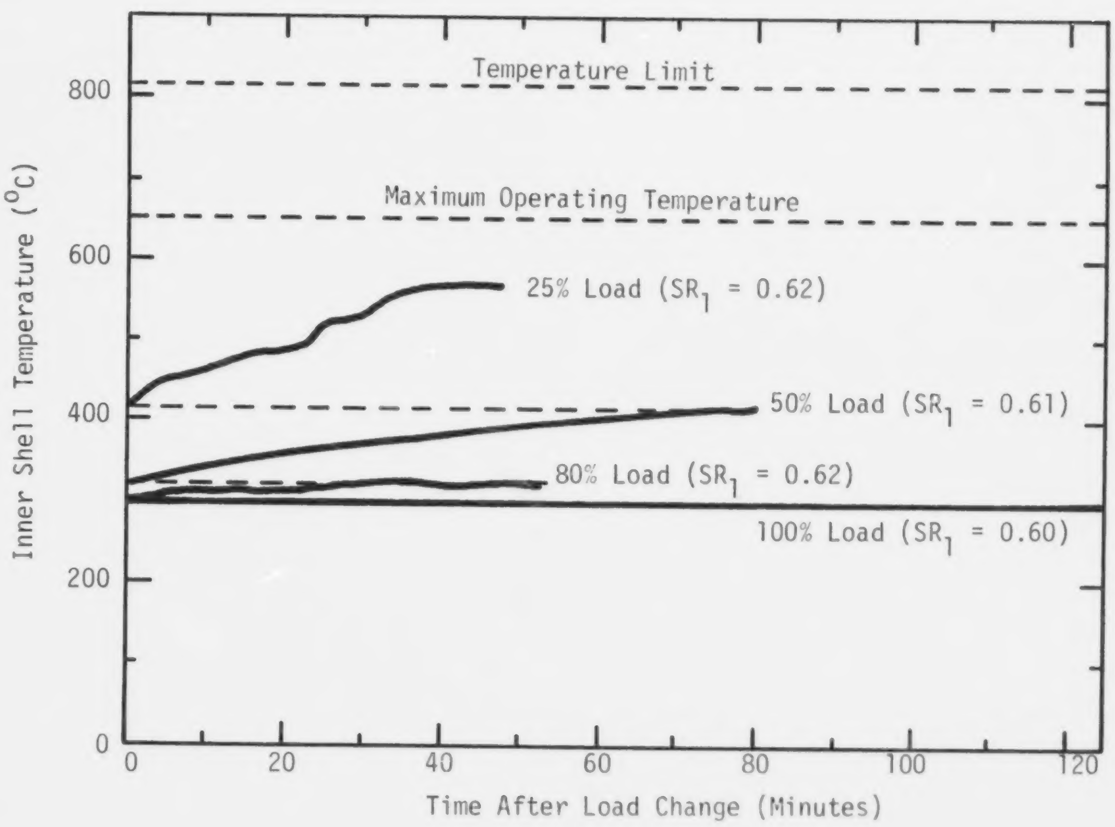


Figure 4-10. Peak shell temperature for different burner turndown ratios.

conditions. Peak shell temperature reached 570° C at 25 percent load with SR_1=0.62. A maximum operating temperature limit of 650° C was specified to prevent potential warpage of the shell. The maximum use temperature of 304 stainless steel before the onset of oxidation is approximately 1200° C. Thus, it can be seen that under normal operating conditions the burner shells appear to operate within acceptable temperature limits.

Figure 4-11 shows the temperature indicated by the four control thermocouples versus load during the fuel tests on the host steam generator. Also shown on the figure is primary air preheat and front wall temperature. The front wall temperature was the highest of the four control thermocouples selected. Front wall temperature at 80 percent load (12.6 MW_t) was approximately 180° C higher than at full load (15.7 MW_t). Primary air preheat increased from 200° C to 270° C as load decreased from 100 to 80 percent of full load.

The most severe conditions for the burner shell occur during a burner shut-down. Figure 4-12 shows front wall temperature when the burner was shut down in the field after an interruption to the host site water supply during an unmanned overnight period. The burner controls are adjusted to provide a two hour post-purge period before the blower is turned off. The purge cycle controls also open a butterfly valve on top of the burner air plenum which vents most of the air during the purge to atmosphere while still maintaining air flow through the burner prechamber and steam generator. This provides maximum cooling of the stainless steel shells while minimizing thermal shock to the refractory in the first stage prechamber. The front wall temperature during steady state operation at full load prior to the shut-down was 210° C. After shut-down temperature decreased to approximately 140° C by the end of the post-purge cycle. Temperature increased sharply after the blower turned off and leveled off at approximately 390° C after six hours from shut-down. Temperature began to decrease after approximately 7 hours. This response is indicative of the tremendous heat storage capacity of the refractory comprising the front wall. Unlike the rest of the refractory lining the front wall has a layer of insulating brick in addition to the high alumina brick which lines the rest of the chamber. For this reason the thermal

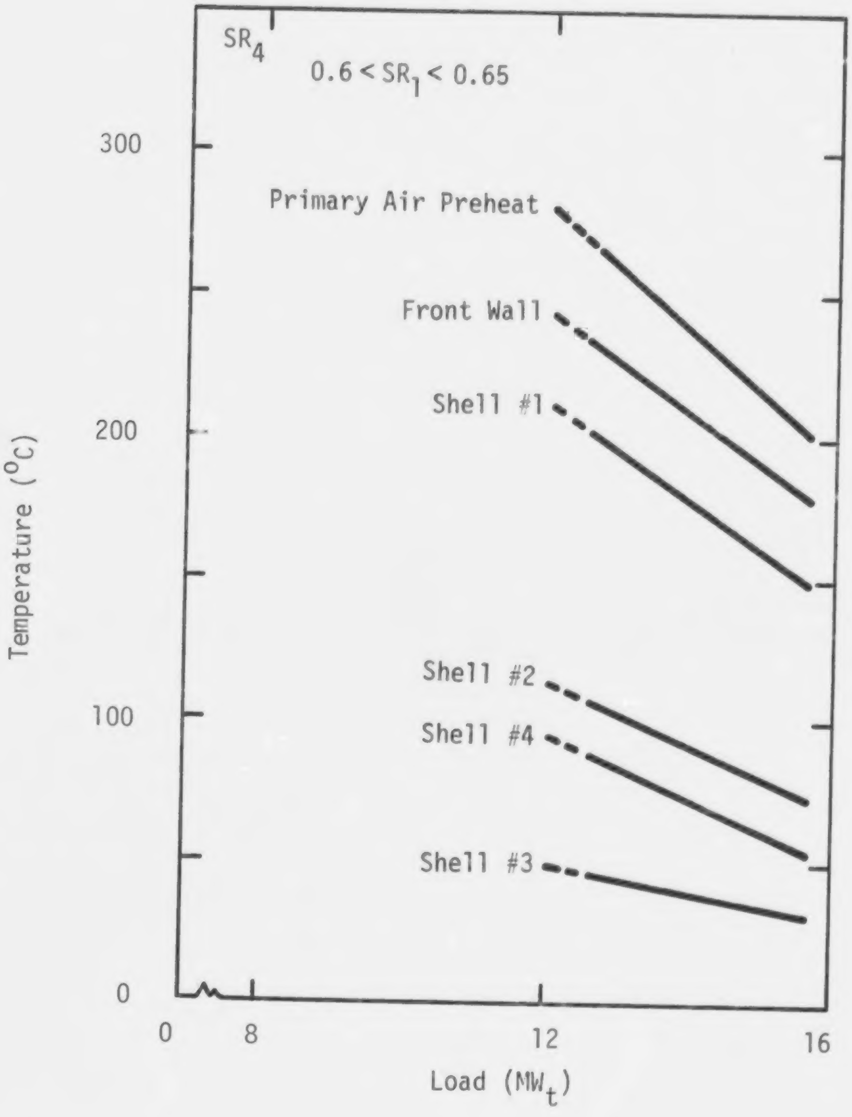


Figure 4-11. Shell temperature profile (Automatic Control).

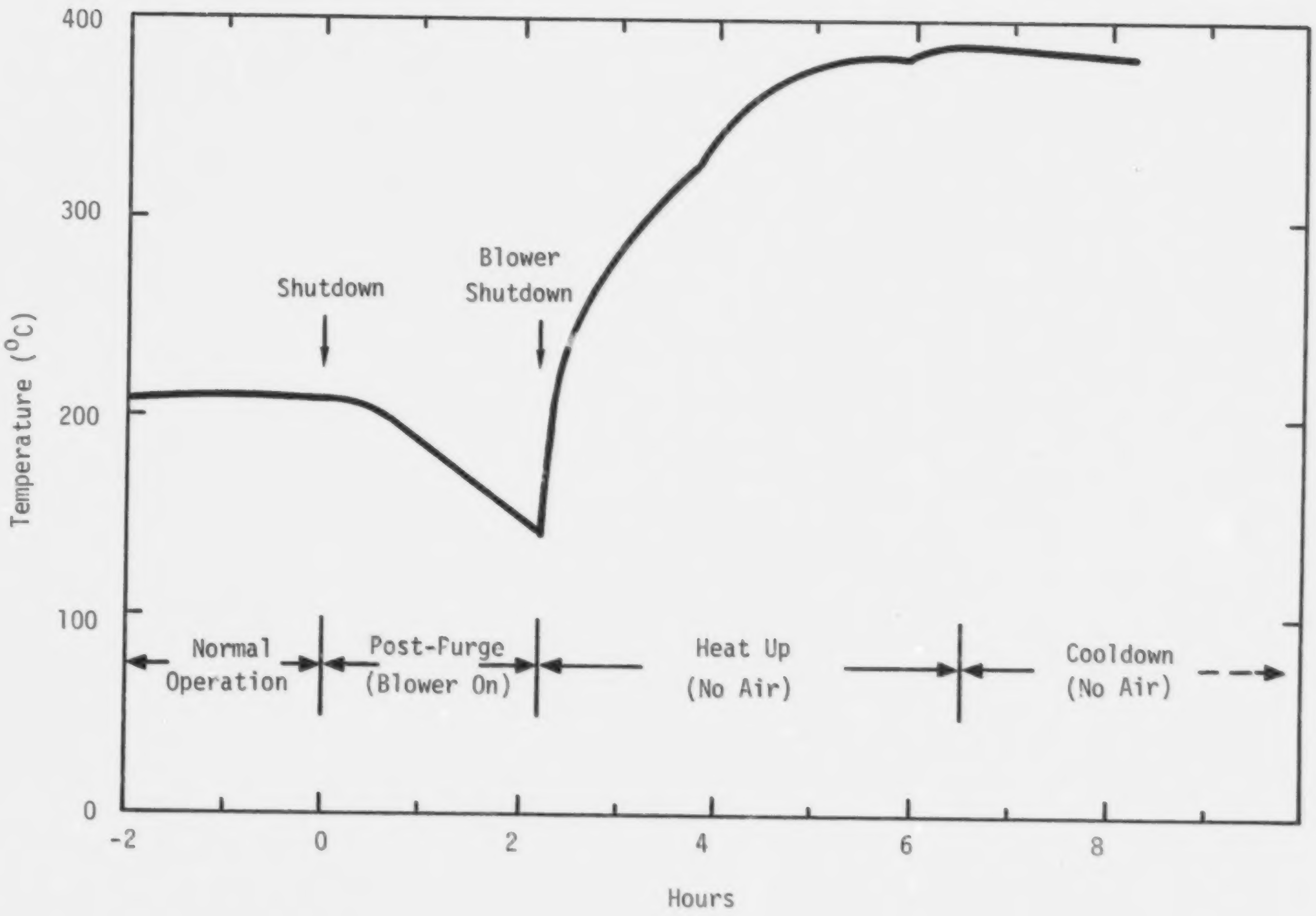


Figure 4-12. Front wall temperature after emergency shutdown of burner.

inertia of the cylindrical portion of the shell is expected to be much less than the front wall.

Although other shell temperatures were monitored overnight during the burner optimization tests it was not possible to determine shell temperature response during loss of power incidents because the recording instrumentation itself was unpowered. However a brief test was conducted during the preliminary evaluation prior to the burner field retrofit to determine shell temperature response during a loss of power shut-down. Figure 4-13 shows peak shell temperature during a brief period following a total power shut-down. The peak temperature rose rapidly at an initial rate of approximately 260° C per hour and ultimately reached 475° C after thirty-five minutes. Because of the steep temperature rise the test was not continued at this time and the blower was restarted. The tests do indicate that shell temperature rises very significantly following a loss of power shut-down; however, the available data indicate that these temperatures will not exceed maximum operating temperature or maximum use limit temperature of the material. Further tests are required to fully characterize the temperature response of the shell during a loss of power shut-down. A detailed inspection of the burner shells following the 30-day test was incomplete because of limited access to the shells. Those areas of the inner shell which were accessible showed only slight discoloration and no apparent warpage.

4.6 Steam Generator Radiant Section

The interior of the steam generator radiant section was also inspected for possible damage to tubes, hangers, and refractory. The radiant section was inspected in detail by both host site and EER personnel before and after the burner retrofit, and was determined to be in the same shape after the 30-day test as it was before the burner retrofit. All insulation and metal surfaces were in excellent condition and showed no sign of deterioration. Prior to the burner retrofit the steam tubes near the exit end of the radiant section and at the entrance to the convective economizer were coated with very light easily removed ash deposits. The tubes in the convective and radiant sections of the steam generator were cleaned before testing the

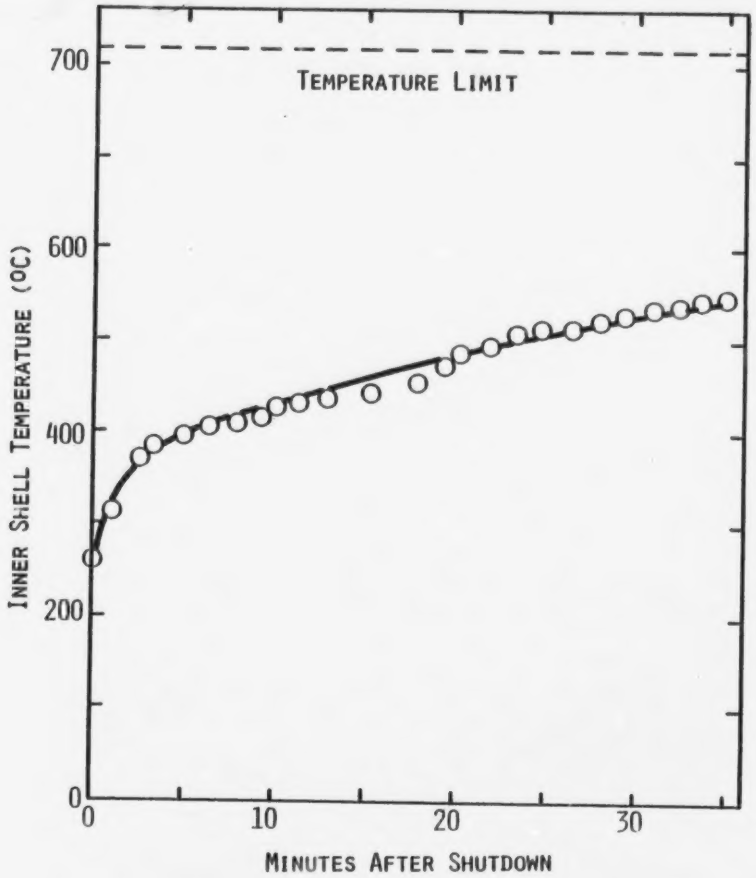


Figure 4-13. Peak shell temperature response following a total burner shut-down (loss of air simulation).

Commercial Prototype Burner. After the 30-day test the distribution of these ash deposits was significantly different in the radiant section. Light ash deposits were located on the steam tubes close to the burner end of the radiant section in the flame region; however tubes in the rear two-thirds of the radiant section were free from ash deposits. Light ash deposits were also observed on the steam tubes at the entrance to the convective economizer section. In general, all tubes, hangers and refractory in the radiant section of the steam generator showed no signs of deterioration or oxidation and appeared to be in the same condition as when the test started.

4.7 Status

Burner performance was reviewed at the completion of the 30-day test with the host site management. Based on the emissions and mechanical performance of the burner the host site management requested that the burner be abandoned in place in lieu of restoration of the steam generator if minor modifications to the burner could be performed. The desired modification included repair of the front wall and first stage exit refractory, a few minor plumbing modifications to reduce pressure drop in the oil line, correction of the control system drift, and the replacement of the existing oil gun diffuser with one of upgraded material for increased temperature resistance. An agreement was reached and, after completion of the modifications, further performance will be evaluated periodically over a six to eight month period to determine long-term mechanical and emissions performance and operating costs.

4.8 Quality Assurance/Quality Control Activities

As part of this program EER implemented a Quality Assurance plan to ensure the measurement data quality for the field evaluation portion of this program. The field evaluation consisted of two parts: (1) burner optimization and (2) a 30-day performance test. The Quality Assurance plan submitted to EPA addressed both parts of the field evaluation with the main emphasis being on the 30-day performance test. EER conducted only the burner optimization portion of the field evaluation; therefore, only that portion of the Quality Assurance plan pertaining to the burner optimization was implemented by EER. Quality Assurance for the 30-day performance test was the responsibility of the firm which conducted those tests (Acurex) and is not discussed in this report outside of Appendix D.

The key objective of the burner optimization tests was to establish the burner operating conditions which minimized NO_x emissions with acceptable CO and smoke emissions as well as acceptable flame characteristics. Therefore the measurements which were important and relevant to this portion of the field evaluation include exhaust gas composition and input measurements required to define and maintain the optimum operating condition. Secondary measurement objectives were to obtain information sufficient to characterize the thermal and mechanical performance of critical burner components. Table 4-14 lists the measurements which were made to establish the necessary performance information.

Several Quality Assurance activities took place during the course of this program. These activities included:

- Internal quality control checks.
- The use of data reduction, validation and reporting procedures consistent with program technical objectives.
- The use of established sampling procedures for obtaining representative samples for subsequent analyses (according to QA Project Plan).
- The use of approved calibration, sample custody and analytical procedures.
- Performance of routine preventive maintenance for critical instrumentation.

TABLE 4-14. KEY MEASUREMENTS RELEVANT TO THE BURNER OPTIMIZATION TESTS

PERFORMANCE PARAMETERS	MEASUREMENTS PARAMETERS
Input Conditions:	
- Thermal load	Fuel flowrate, fuel composition.
- Primary zone stoichiometry	Fuel flowrate, fuel composition, primary air flowrate.
- Excess Air	Exhaust gas oxygen.
Output Conditions:	
- Exhaust gas composition	O_2, CO_2, CO, NO_x, SO_2, hydrocarbons particulate mass, particulate size, HCN, NH_3, heavy hydrocarbons, smoke spot.
Thermal Performance:	
- Steam generator efficiency	Thermal load, heat output, exhaust gas composition, exhaust gas temperature
- Burner shells	Shell temperatures, primary air preheat, primary air flowrate, primary exit temperature.
Mechanical Performance:	
- Refractory	Visual inspection, shell temperatures
- Misc. components	Visual inspection.

In addition to these specific activities, test plans and procedures were informally reviewed with the EER Quality Assurance Officer to assure that project quality assurance objectives were satisfied. Due to the extremely short duration of the burner optimization tests, it was not appropriate to conduct an internal quality assurance audit.

The specific quality control checks which were conducted during the course of the burner optimization tests are shown in Table 4-15. The frequency of several of the quality assurance checks which were performed was somewhat reduced as appropriate to the burner optimization tests. The planned frequency of quality assurance checks shown in the table was directed primarily at ensuring the quality of data obtained during the 30-day evaluation. The execution of these quality control checks, as shown in the Table, serve to achieve both the quality assurance goals and technical goals of the program in the most efficient manner.

Table 4-16 compares the quality assurance data achievements with expectations. The achieved levels of relative standard deviation were within program goals where replicate measurements were appropriate, with the exception of the two Method 5 particulate measurements. The high relative standard deviation shown is most likely a result of the very low absolute level of particulate emissions measured in the stack. Comparison of the particulate measurement results obtained during the burner optimization tests with results obtained during the 30-day continuous performance test, confirms the very low level of stack emissions.

Objectives for data accuracy and completeness were also achieved for all measurements which were checked. The accuracy of the continuous emissions monitors was well within the limits prescribed by EPA Performance Specifications 2 and 3 for O_2, CO_2 and NO_x analyzers. Subsequent exhaust gas emission measurements under similar burner operating conditions during the 30-day continuous performance test confirmed the overall accuracy of the emissions monitoring system. The overall success of the program and acceptance of the burner by the host site owners testifies to the overall quality and reliability of the data which was obtained in this program.

TABLE 4-15. INTERNAL QUALITY CONTROL CHECKS

MEASUREMENT PARAMETER		QUALITY CONTROL CHECKS	FREQUENCY	
			PLANNED	ACTUAL
Fuel Flow Rate		Calibration by manufacturer	Once prior to purchase	Once prior to purchase.
		Compare to micromotion meter	Once during field test	Weekly compared to positive displacement flowmeter
		Mass balance	Each particulate test	Each particulate test
Combustion Air Distribution		Calibrate transducers	At beginning of test	At beginning of test
			Weekly	Daily check against manometer reading
			Each particulate test	
Combustion Air Temperature		Calibrate with thermometer	At beginning and end of test	At beginning of tests
Fuel Temperature		Calibrate with thermometer	At beginning and end of test	Check daily against thermometer reading
Fuel Composition		Duplicate samples	Each ten samples	4 samples for nitrogen
		Interlaboratory analysis	At beginning and end of test	ND
Exhaust Gas Composition	NO_x, O_2, CO, CO_2, hydrocarbons	Calibration with compressed gas standards	Daily	Daily
		Compare to reference methods (NO_x, O_2, CO_2 only)	At beginning and end of tests	At end of tests.
	HCN, NH_3	Calibration with liquid standards	Daily	Daily
		Blanks	Daily	Daily
		Replicate analysis	Each test	Each test
	N_2O	Calibrate with gas standards	Daily	ND
		Replicate analyses (3)	Each test	ND
		Spiked samples		ND
Burner Primary Zone		Calibrate thermocouple output	At beginning and end of tests	ND
Particulate and Particle Size Distribution		Calibrate test equipment	At beginning and end of tests	ND
		Replicate analyses	Daily tests	ND
		Reagent and filter blanks	Each ten analyses	N/A
		Gas flow rate mass balance	Each particulate test	ND
Heavy hydrocarbons		Calibrate GC/FID	Daily	Outside lab
		Replicate analyses (3)	Each test	Duplicate samples
Smoke		Compare with visual observations	Each test	Each test

ND: Not determined, not required for burner optimization tests.

TABLE 4-16. COMPARISON OF DATA ACHIEVEMENTS WITH EXPECTATIONS

MEASUREMENT PARAMETER		METHOD/INSTRUMENT	EXPERIMENTAL CONDITIONS	PRECISION, RELATIVE STANDARD DEVIATION		ACCURACY		COMPLETENESS		REFERENCE METHOD
				OBJECTIVE	ACHIEVED	OBJECTIVE	ACHIEVED	OBJECTIVE	ACHIEVED	
Fuel Flowrate		Turbine Meter	Fuel Oil	1%	ND	2%	0.3%	100%	100%	Positive Displacement Flowmeter
Combustion Air Distribution		Pressure Transducers	Ambient Air	5%	ND	10%	6.9	90%	100%	
Combustion Air Temperature		Thermocouple	Ambient Air	1%	ND	1.5%	ND	90%	100%	EPA Method 2
Fuel Temperature		Thermocouple	Fuel Oil	1%	ND	1.5%	ND	90%	100%	
FUEL COMPOSITION	Carbon	ASTM E191	Fuel Oil	2%	ND	7%	ND	90%	100%	
	Hydrogen	ASTM E191	Fuel Oil	5%	ND	5%	ND	90%	100%	
	Nitrogen	ASTM E258	Fuel Oil	10%	<1%	10%	ND	90%	100%	
	Oxygen	Difference	Fuel Oil	10%	ND	10%	ND	90%	100%	
	Sulfur	ASTM D129	Fuel Oil	10%	ND	10%	ND	90%	100%	
	Ash	ASTM D482	Fuel Oil	10%	ND	10%	ND	90%	100%	
	Heating Value	ASTM D240	Fuel Oil	2%	ND	2%	ND	90%	100%	
PRIMARY ZONE GAS COMPOSITION	NO_x	Chemiluminescent	In-Flame Gas	2%	ND	20%	ND	90%	ND	EPA Performance Spec. 2
	O_2	Paramagnetic	In-Flame Gas	2%	ND	20%	ND	90%	ND	EPA Performance Spec. 3
	CO	Infrared	In-Flame Gas	2%	ND	20%	ND	90%	ND	
	CO_2	Infrared	In-Flame Gas	2%	ND	20%	ND	90%	ND	EPA Performance Spec. 3
	Hydrocarbons	Flame Ionization	In-Flame Gas	2%	ND	20%	ND	90%	ND	
	HCN, NH_3	Specific Ion Electrode	In-Flame Gas	10%	ND	10%	ND	80%	ND	
Primary Zone Gas Temperature		Suction Pyrometer	In-Flame Gas	1%	ND	1.5%	ND	90%	100%	
Refractory, Shell, and Component Temperature		Thermocouple	Refractory and Steel	1%	ND	1.5%	ND	90%	100%	
Exhaust Gas Temperature		EPA Method 2	Exhaust Gas	1%	ND	1.5%	ND	90%	100%	EPA 600/4-76-044
Exhaust Gas Flowrate		EPA Method 2	Exhaust Gas	10%	ND	10%	ND	90%	100%	EPA 600/4-76-044
EXHAUST GAS COMPOSITION	NO_x	Chemiluminescent	Exhaust Gas	2%	ND	20%	7	90%	100%	EPA Performance Spec. 3
	O_2	Paramagnetic	Exhaust Gas	2%	ND	20%	15	90%	100%	EPA Performance Spec. 3
	CO	Infrared	Exhaust Gas	--	--	--	--	90%	100%	
	CO_2	Infrared	Exhaust Gas	2%	ND	20%	2	90%	100%	EPA Performance Spec. 3
	Hydrocarbons	Flame Ionization	Exhaust Gas	2%	ND	20%	ND	90%	100%	
	HCN, NH_3	Specific Ion Electrode	Exhaust Gas	10%	ND	10%	ND	80%	100%	
	N_2O	Gas Chromatograph	Exhaust Gas	10%	ND	10%	ND	80%	ND	
	Particulate	EPA Method 5	Exhaust Gas	10%	19.5%	--	--	80%	100%	EPA 600/4-76-044
	Moisture	EPA Method 4	Exhaust Gas	2%	ND	5%	ND	80%	100%	EPA 600/4-76-044
	Particle Size Distribution	Cascade Impactor	Exhaust Gas	10%	ND	--	--	80%	100%	EPA 600/2-77-004
	Heavy Hydrocarbons	Gas Chromatograph	Exhaust Gas	20%	11.6%	10%	ND	80%	100%	
	Smoke Spot	Bacharach Meter	Exhaust Gas	10%	ND	--	--	90%	100%	

ND = not determined; not required for burner optimization tests.

Further information on the Quality Assurance activities conducted during this program can be found in Appendix B.

5.0 CONCLUSIONS

The field test of the Commercial Prototype Burner showed that:

- the burner concept could be successfully scaled up based on pilot- and bench-scale information and applied to a full-scale field operating TEOR steam generator;
- average NO_x emissions from the TEOR steam generator operating at full load averaged 70 ppm during the 30-day test;*
- NO_x emissions as low as 60 ppm were achieved during the burner optimization test;
- flame shape was acceptable, CO was below 50 ppm, and particulate emissions were below 43 g/kJ under full load minimum NO_x conditions;
- the burner technology was accepted by the host;
- long term efficiency and operating costs could not be fully established over the short duration of these tests;
- all technical goals were achieved.

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*At the time this report was prepared, only nine days of actual continuous monitoring data had been averaged by Acurex. Acurex reported that inspection of strip chart recordings of continuous monitor outputs showed NO_x levels consistent with this nine-day average for the remainder of the 30-day test period.

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ACKNOWLEDGEMENTS

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APPENDIX A

SASS TRAIN ANALYSIS

S-CUBED
A Division of Maxwell Laboratories, Inc.

S-CUBED Reference No.: 42041-23

Mr. Glen England
Energy and Environmental
Research Corporation
18 Mason
Irvine, California 92714

Dear Glen:

Attached please find the results from the analysis of SASS train samples delivered to our laboratory. As per your instructions, all samples relating to a single SASS train were extracted, including XAD resin, washes, condensate and filter paper. Table I lists the results from the analysis of the two SASS train total extracts, two blanks and a matrix spike sample. The Table also contains the Hazardous Substance List compounds which were detected in the samples. A mass spectral library search was also performed in order to determine additional compounds in the sample. The search yielded a variety of compounds in several classes. These include benzaldehyde, benzoic acids, phenols, higher weight alkylbenzenes, higher weight aliphatic acids, hydrocarbons and alcohols. These were all present at fewer than 10 ugs in the sample.

Also attached are the reconstructed ion chromatograms from the mass spectrometer analysis.

Should you have any questions or need further assistance, please do not hestiate to call.

Sincerely,

Jim

James E. Picker

JEP:vk (1250V)

P.O. Box 1620, La Jolla, California 92038-1620 3398 Carmel Mountain Road, San Diego, California 92121-1095
Tel: (619) 453-0060 TWX: 910-337-1253 Telecopier: (619) 755-0474

TABLE I

SASS TRAIN GC/MS ANALYSIS

SASS01 (104863-104867)
BLK01 (104898)
SASS02 (104882-104889)
BLK02 (104870+104901)

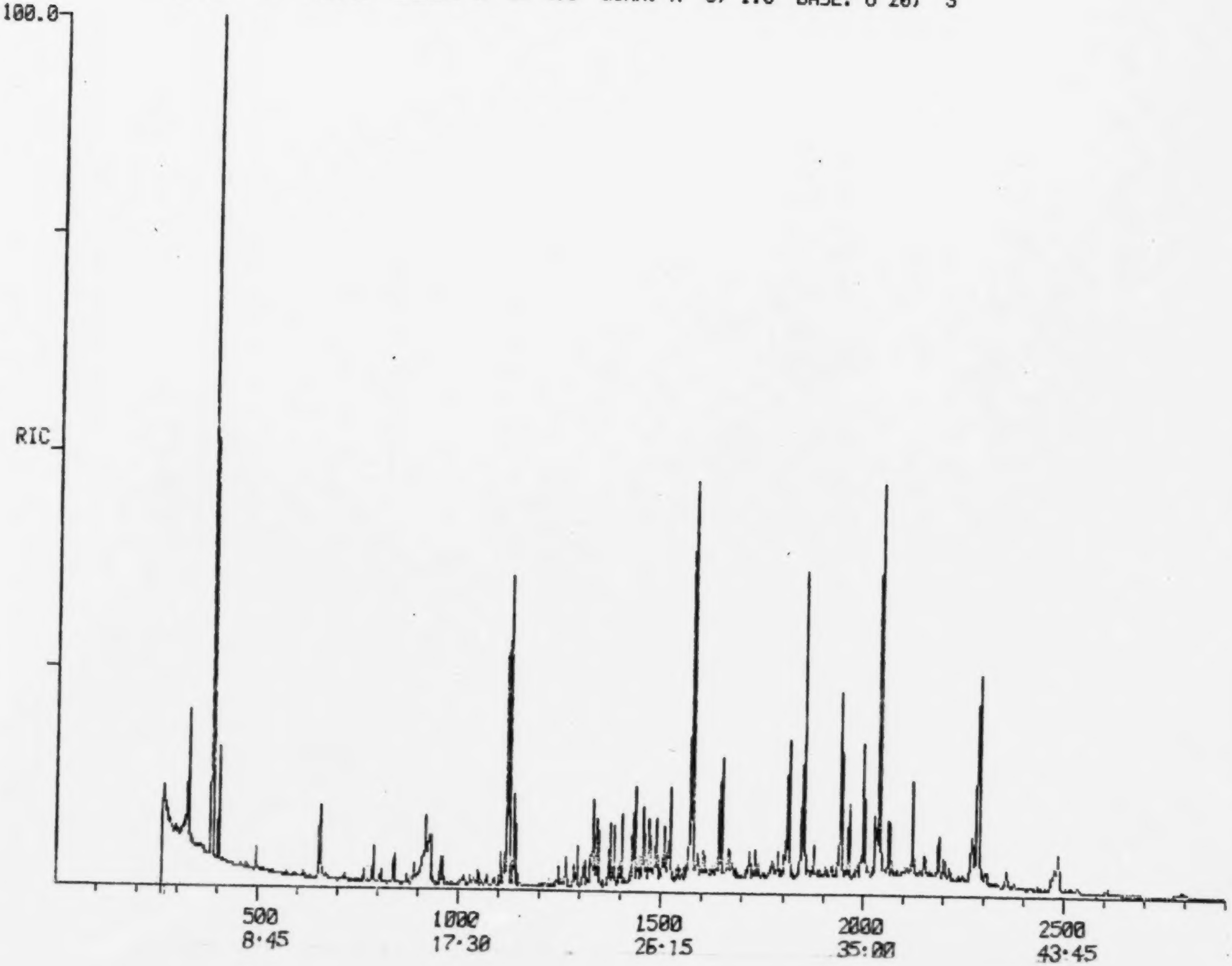
SURROGATES (Percent Recovery)	SASS01	SASS02	BLK01	BLK02	MTRX
(d_5)Nitrobenzene	53	42	65	85	36
(d_5)Phenol	49	37	62	76	25
2-Fluorophenol	42	34	64	30	35
Decafluorobiphenyl	48	48	67	97	41
2-Fluorobiphenyl	50	56	17	55	46
2,4,6-Tribromophenol	49	40	ND	ND	33
(d_{14})Terphenyl	102	77	94	96	58

HAZARDOUS SUBSTANCE LIST

COMPOUNDS (μg detected)	SASS01	SASS02	BLK01	BLK02	MTRX
2-Chlorophenol	ND	ND	ND	ND	79
Phenol	144	190	ND	ND	70
1,4,-Dichlorobenzene	ND	ND	ND	ND	74
N-nitroso-di-n-propylamine	ND	ND	ND	ND	91
1,2,4-Trichlorobenzene	ND	ND	ND	ND	24
p-chloro-m-cresol	ND	ND	ND	ND	48
Hexachlorocyclopentadiene	ND	ND	ND	ND	56
2,4-Dinitrotoluene	ND	ND	ND	ND	78
Acenapthene	ND	ND	ND	ND	50
Pentachlorophenol	ND	ND	ND	ND	42
Di-n-butyl phthalate	63	61	2.0	4.8	65
Pyrene	ND	ND	ND	ND	103
Bis(2-ethylhexyl)phthalate	101	178	15	43	3
Napthalene	7.6	10	4.5	7.9	ND
Butylbenzyl phthalate	5.5	5.5	ND	ND	ND
Di-n-octyl phthalate	10	11	ND	3.8	ND
Phenanthrene	2.5	2.8	ND	ND	ND

ND = Not detected.

RIC
02/17/84 13:35:00 DATA: EERSASS01 #1 SCANS 1 TO 2
CALI: 17CALI #4
SAMPLE: EER COMBINED EXTRACTS FV=1.45ML + 20PPM IS SASS01
RANGE: G 1,2900 LABEL: N 0, 4.0 QUAN: A 0, 1.0 BASE: U 20, 3



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RIC                                                                  DATA: EERSASS02 #1          SCANS    1 TO 2
02/17/84 15:36:00                                                    CALI: 17CALI #4
SAMPLE: EER COMBINED EXTRACTS FV=1.45ML+20PPM DFB+50PPM IS SASS02GROUP
RANGE: G   1,2900  LABEL: N  0, 4.0  QUAN: A  0, 1.0  BASE: U 20,  3
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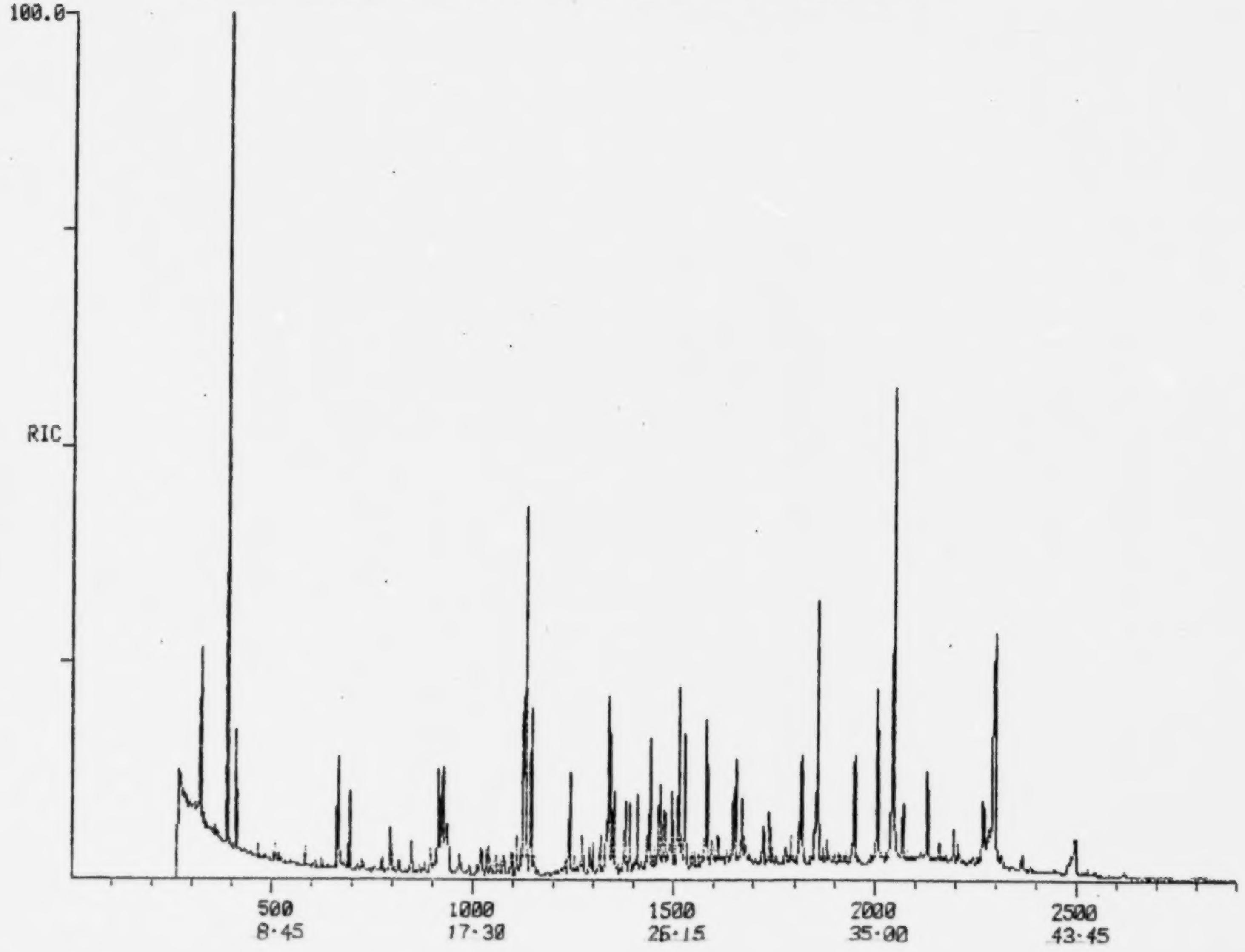


APPENDIX B - Quality Assurance

The following tables present the results of several quality assurance activities conducted during this program. Quality Control checks included:

B.1 - Tracking calibration gases used for calibration of the continuous monitors during all tests, and reported composition of high-grade gases.

B.2 - Frequent calibration of the continuous emission monitors to ensure data accuracy. Sample strip chart recording showing instrument calibration presented.

B.3 - Verification of accuracy of continuous emissions monitors by comparison with EPA Reference Methods. Laboratory report presented.

B.4 - Routine logging of all critical burner and steam generator parameters to ensure adequate characterization of input/output conditions. Sample data log presented.

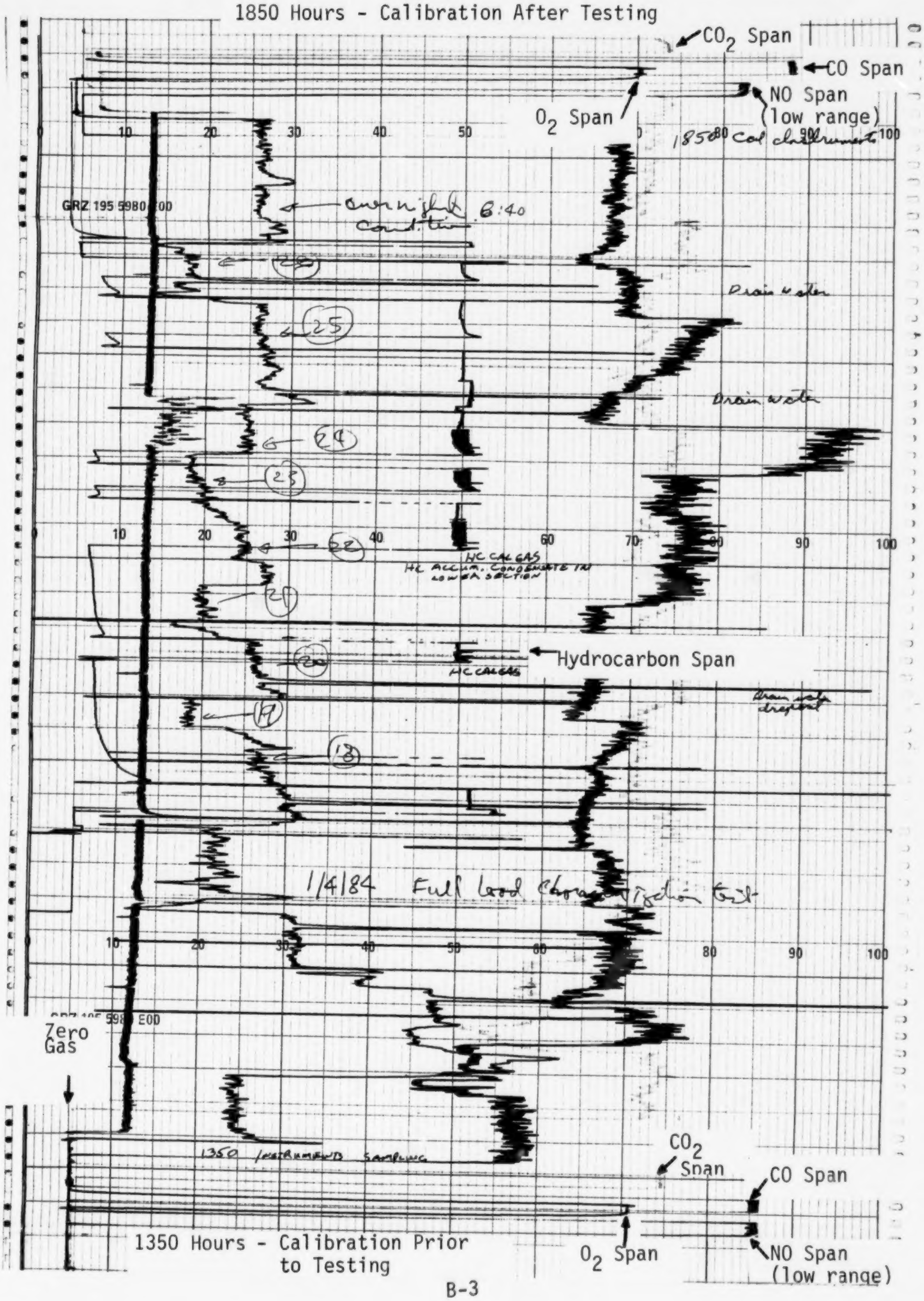
B.5 - Kern County crude oil analysis by outside laboratory. Report presented.

B.6 - Verification of repeatable fuel nitrogen determinations. Laboratory report presented.

B.1 Continuous Emission Monitor Calibration Gases

Composition	Bottle No.	Reported Composition	Date
CO_2/Bal N_2	T-684617 (Linde)	14.01%	5/25/82
O_x/Bal N_2	K-273551 (Linde	9.94%	1/15/82
NO/Bal N_2	T-705169 (Linde)	208 ppm	10/8/82
NO/Bal N_2	T-386418 (Linde)	81 ppm	3/19/82
CO/Bal N_2	T-208842 (Linde)	400 ppm	9/1/82
C_3H_8/Bal N_2	A-8484 (Scott)	46.2 ppm	12/13/82

B.2. TYPICAL STRIP CHART SHOWING CONTINUOUS EMISSION MONITOR CALIBRATION



B.3 Laboratory Analysis of Flue Gas Samples.

REPORT

TRUESDAIL LABORATORIES, INC.

CHEMISTS - MICROBIOLOGISTS - ENGINEERS
RESEARCH — DEVELOPMENT — TESTING

14201 FRANKLIN AVENUE
TUSTIN, CALIFORNIA 92680
AREA CODE 714 • 730-6239
AREA CODE 213 • 225-1564
CABLE: TRUELABS

CLIENT Energy and Environmental Research
18 Mason
Irvine, California 92714
Attention: Glen England

SAMPLE 6PDSA Flasks

P.O. NO. 25582

DATE January 17, 1984

RECEIVED January 11, 1984

LABORATORY NO. 52531

INVESTIGATION

Nitrogen Oxides, Oxygen, Carbon Dioxide and Carbon Monoxide

RESULTS

The submitted samples were analyzed for nitrogen oxides (NO_x) by the phenoldisulfonic acid (PDSA) method, for oxygen (O_2) and carbon dioxide (CO_2) by Orsat and for carbon monoxide (CO) by gas chromatography with flame ionization detection.

The results are as follows:

Test Time	Flask No.	CO_2 %	O_2, %	Nitrogen Oxides		CO ppm
				ppm DRY	@ 3% O_2	
1645	50	13.0	3.5	77	79	<1
1648	1482	12.7	3.7	69	72	<1
1650	1327	13.3	3.0	73	73	<1
1651	1345	13.0	3.5	67	69	<1
1652	1309	13.2	3.2	74	75	<1
1653	3966	13.4	3.0	77	77	<1

Respectfully submitted,

TRUESDAIL LABORATORIES, INC.

S. Hugh Brown

S. Hugh Brown, Supervisor
Air Pollution Testing

This report applies only to the sample, or samples, investigated and is not necessarily indicative of the quality or condition of apparently identical or similar products. As a mutual protection to clients, the public and these Laboratories, this report is submitted and accepted for the exclusive use of the client to whom it is addressed and upon the condition that it is not to be used, in whole or in part, in any advertising or publicity matter without prior written authorization from these Laboratories.

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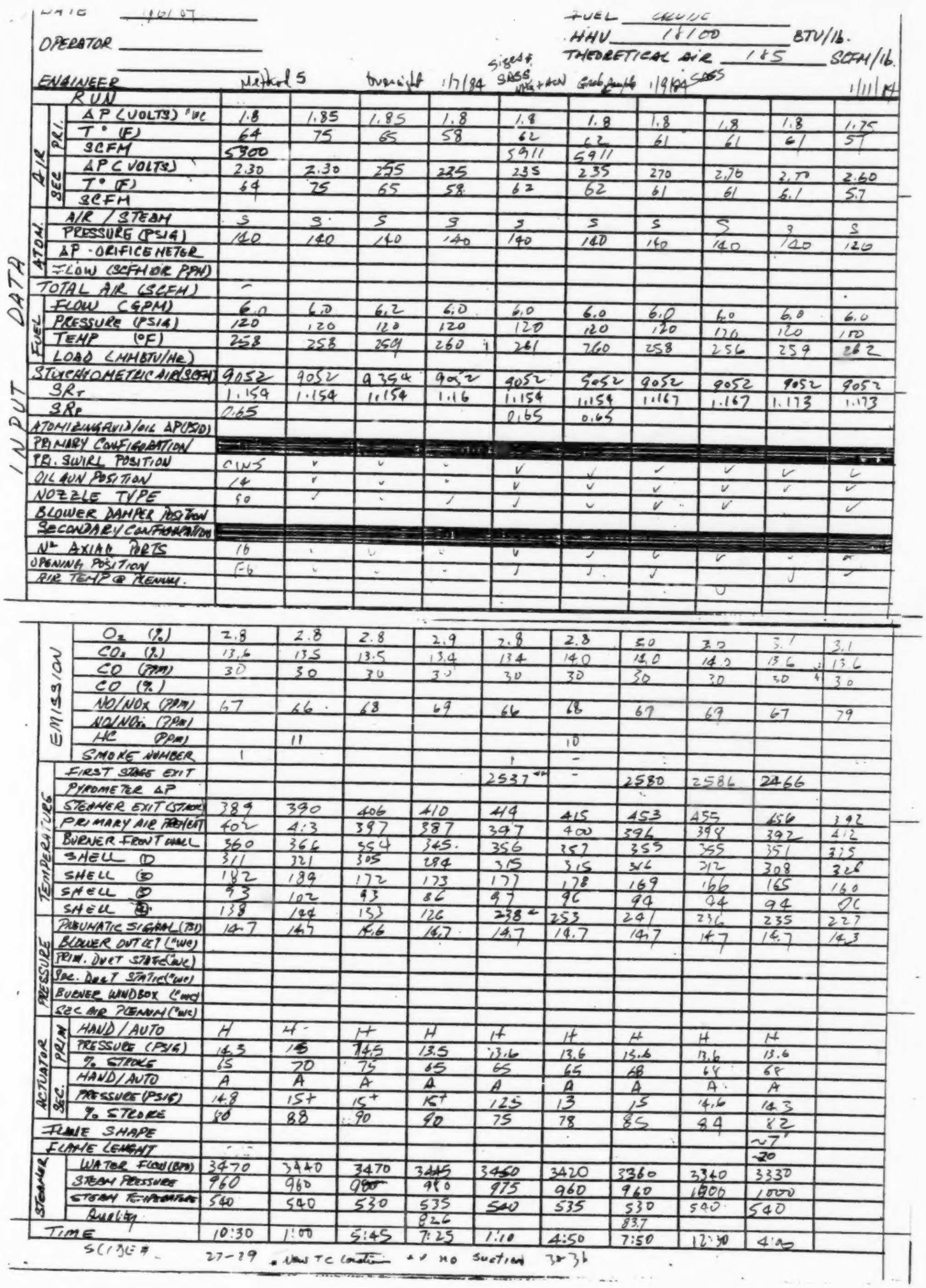
B.4 Typical Data Log.



DATE 1/6/84
OPERATOR
ENGINEER

FUEL CRUDE
HHV 18100 BTU/lb.
THEORETICAL AIR 185 SCFM/lb.

ENGINEER		Method 5		Overnight	1/7/84	Sieges & SASS NH3+HCN	Grab sample	1/9/84	SASS		1/11/84
RUN											
AIR PRI.	ΔP (VOLTS) "WC	1.8	1.85	1.85	1.8	1.8	1.8	1.8	1.8	1.8	1.75
	T° (F)	64	75	65	58	62	62	61	61	61	57
	SCFM	5300				5911	5911				
AIR SEC	ΔP (VOLTS)	2.30	2.30	235	235	235	235	270	2.70	2.70	2.60
	T° (F)	64	75	65	58	62	62	61	61	6.1	5.7
	SCFM										
ATOM.	AIR / STEAM	S	S	S	S	S	S	S	S	S	S
	PRESSURE (PSIA)	140	140	140	140	140	140	140	140	140	120
	ΔP - ORIFICE METER										
	FLOW (SCFH OR PPH)										
TOTAL AIR (SCFM)		–									
FUEL	FLOW (GPM)	6.0	6.0	6.2	6.0	6.0	6.0	6.0	6.0	6.0	6.0
	PRESSURE (PSIA)	120	120	120	120	120	120	120	120	120	120
	TEMP (°F)	258	258	259	260	261	260	258	256	259	262
	LOAD (MMBTU/HR)										
STOICHIOMETRIC AIR (SCFM)		9052	9052	9354	9052	9052	9052	9052	9052	9052	9052
SR_T		1.154	1.154	1.154	1.16	1.154	1.154	1.167	1.167	1.173	1.173
SR_P		0.65				0.65	0.65				
ATOMIZING FLUID/OIL ΔP (PSID)											
PRIMARY CONFIGURATION											
PRI. SWIRL POSITION		CW5	✓	✓	✓	✓	✓	✓	✓	✓	✓
OIL GUN POSITION		14	✓	✓	✓	✓	✓	✓	✓	✓	✓
NOZZLE TYPE		50	✓	✓	✓	✓	✓	✓	✓		✓
BLOWER DAMPER POSITION											
SECONDARY CONFIGURATION											
N° AXIAL PORTS		16	✓	✓	✓	✓	✓	✓	✓	✓	✓
OPENING POSITION		F-6	✓	✓	✓	✓	✓	✓		✓	✓
AIR TEMP @ PLENUM											
EMISSION	O_2 (%)	2.8	2.8	2.8	2.9	2.8	2.8	3.0	3.0	3.1	3.1
	CO_2 (%)	13.6	13.5	13.5	13.4	13.4	14.0	14.0	14.0	13.6	13.6
	CO (PPM)	30	30	30	30	30	30	30	30	30	30
	CO (%)										
	NO/NOx (PPM)	67	66	68	69	66	68	67	69	67	79
	NO/NOx (PPM)										
	HC (PPM)		11				10				
	SMOKE NUMBER	1				1	–				
TEMPERATURE	FIRST STAGE EXIT					2537	–	2580	2586	2466	
	PYROMETER ΔP										
	STEAMER EXIT (STACK)	389	390	406	410	414	415	453	455	456	392
	PRIMARY AIR PREHEAT	402	413	397	387	397	400	396	398	392	412
	BURNER FRONT WALL	360	366	354	345	356	357	355	355	351	315
	SHELL ①	311	321	305	284	315	315	316	312	308	326
	SHELL ②	182	189	172	173	177	178	169	166	165	160
	SHELL ③	93	102	93	86	97	96	94	94	94	90
	SHELL ④	138	144	153	126	238	253	241	236	235	227
PRESSURE	PNEUMATIC SIGNAL (PSI)	14.7	14.7	14.6	14.7	14.7	14.7	14.7	14.7	14.7	14.3
	BLOWER OUTLET ("WC)										
	PRIM. DUCT STATIC ("WC)										
	SEC. DUCT STATIC ("WC)										
	BURNER WINDBOX ("WC)										
	SEC AIR PLENUM ("WC)										
ACTUATOR PRIM	HAND / AUTO	H	H	H	H	H	H	H	H	H	
	PRESSURE (PSIG)	14.3	15	14.5	13.5	13.6	13.6	13.6	13.6	13.6	
	% STROKE	65	70	75	65	65	65	68	68	68	
ACTUATOR SEC.	HAND / AUTO	A	A	A	A	A	A	A	A	A	
	PRESSURE (PSIG)	14.8	15+	15+	15+	12.5	13	15	14.6	14.3	
	% STROKE	80	88	90	90	75	78	85	84	82	
FLAME SHAPE										~7'	
FLAME LENGTH										~20	
STEAMER	WATER FLOW (BPD)	3470	3440	3470	3445	3450	3420	3360	3340	3330	
	STEAM PRESSURE	960	960	980	980	975	960	960	1000	1000	
	STEAM TEMPERATURE	540	540	530	535	540	535	530	540	540	
	Quality				82.6			83.7			
TIME		10:30	1:00	5:45	7:25	1:10	4:50	7:50	12:30	4:00	

SCIBE# – 27-29 • New TC Location •• NO Suction 32-36

B.5. Kern County crude oil analysis.

REPORT

TRUESDAIL LABORATORIES, INC.

CHEMISTS - MICROBIOLOGISTS - ENGINEERS
RESEARCH - DEVELOPMENT - TESTING

14201 FRANKLIN AVENUE
TUSTIN, CALIFORNIA 92680
AREA CODE 714 • 730-6239
AREA CODE 213 • 225-1564
CABLE: TRUELABS

CLIENT Energy & Environmental Research Corp.
18 Mason
Irvine, California 92714
ATTN: Yul Kwan

DATE January 26, 1984
RECEIVED December 15, 1984
LABORATORY NO. 52594

SAMPLE 1 Sample Fuel Oil, #104857

P.O. No: 25443

INVESTIGATION Analysis As Requested

RESULTS

Heating Value, Btu/lb.	18310
Viscosity, SSF @ 140°F	245
Viscosity, SSU @ 210°F	274
Ultimate Analysis:	
Carbon, %	85.42
Hydrogen, %	10.88
Nitrogen, %	0.83
Sulfur, %	1.05
Ash, %	0.027
Oxygen, by difference, %	1.79
Specific gravity @ 60°/60°	0.9779

Respectfully submitted,

TRUESDAIL LABORATORIES, INC.

Ignas Bandziulis
Ignas Bandziulis
Chief Chemist

IB:pjp

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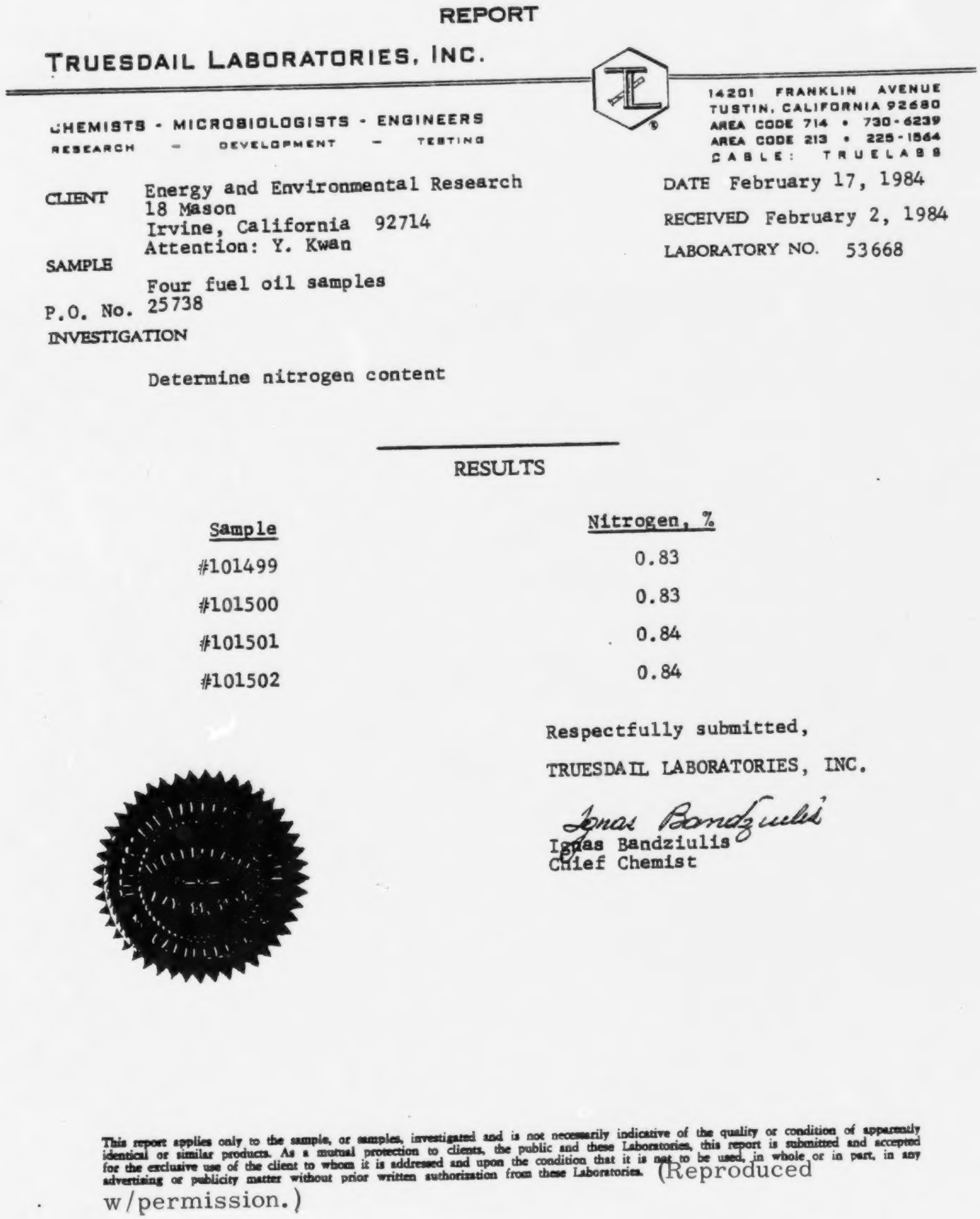
B.6. Replicate fuel nitrogen determinations for Kern County crude oil.



REPORT

TRUESDAIL LABORATORIES, INC.

CHEMISTS - MICROBIOLOGISTS - ENGINEERS
RESEARCH — DEVELOPMENT — TESTING

14201 FRANKLIN AVENUE
TUSTIN, CALIFORNIA 92680
AREA CODE 714 • 730-6239
AREA CODE 213 • 225-1564
CABLE: TRUELABS

CLIENT Energy and Environmental Research
18 Mason
Irvine, California 92714
Attention: Y. Kwan

DATE February 17, 1984

RECEIVED February 2, 1984

LABORATORY NO. 53668

SAMPLE Four fuel oil samples

P.O. No. 25738

INVESTIGATION Determine nitrogen content

RESULTS

Sample	Nitrogen, %
#101499	0.83
#101500	0.83
#101501	0.84
#101502	0.84

Respectfully submitted,

TRUESDAIL LABORATORIES, INC.

Ignas Bandziulis

Ignas Bandziulis
Chief Chemist

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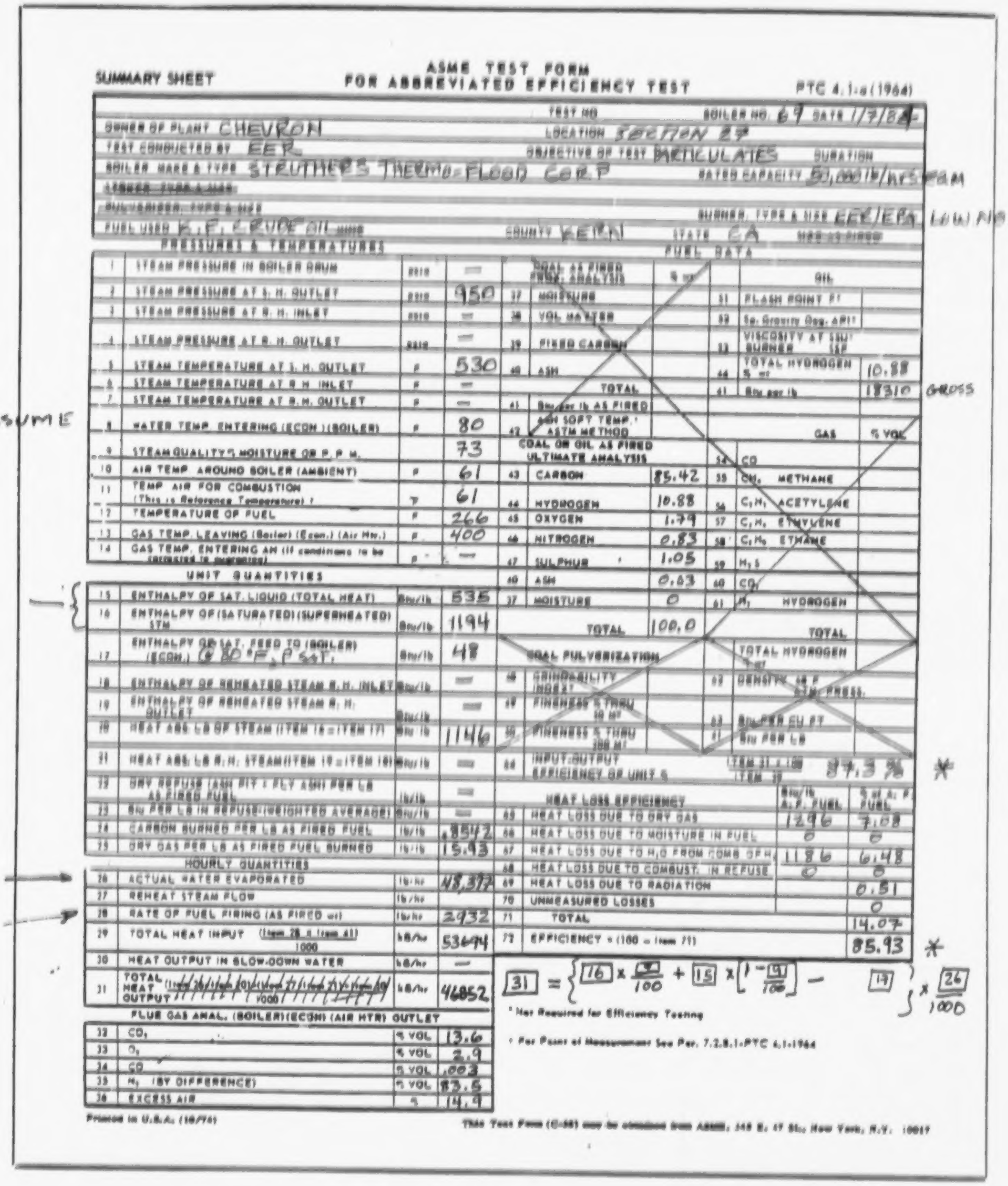
APPENDIX C - Steam Generator Efficiency

Examples of calculation steam generator efficiency by ASME methods:

C.1 - Test by EER on 1/7/84, after burner retrofit.

C.2 - Efficiency calculation for steam generator design conditions based on manufacturer's information.

C.1 Thermal Efficiency Determined During Long Term Evaluation.



SUMMARY SHEET

ASME TEST FORM
FOR ABBREVIATED EFFICIENCY TEST

PTC 4.1-a (1964)

TEST NO BOILER NO. 69 DATE 1/7/84
OWNER OF PLANT CHEVRON LOCATION SECTION 27
TEST CONDUCTED BY EER OBJECTIVE OF TEST PARTICULATES DURATION
BOILER MAKE & TYPE STRUTHERS THERMO-FLOOD CORP RATED CAPACITY 50,000 lb/hr STEAM
STOKER TYPE & SIZE
PULVERIZER, TYPE & SIZE BURNER, TYPE & SIZE EER/EPA LOW NOx
FUEL USED K.F. CRUDE OIL MINE COUNTY KERN STATE CA SIZE AS FIRED

ASSUME

PRESSURES & TEMPERATURES

1	STEAM PRESSURE IN BOILER DRUM	psia	—
2	STEAM PRESSURE AT S. H. OUTLET	psia	950
3	STEAM PRESSURE AT R. H. INLET	psia	—
4	STEAM PRESSURE AT R. H. OUTLET	psia	—
5	STEAM TEMPERATURE AT S. H. OUTLET	F	530
6	STEAM TEMPERATURE AT R. H. INLET	F	—
7	STEAM TEMPERATURE AT R. H. OUTLET	F	—
8	WATER TEMP. ENTERING (ECON.) (BOILER)	F	80
9	STEAM QUALITY % MOISTURE OR P. P. M.		73
10	AIR TEMP. AROUND BOILER (AMBIENT)	F	61
11	TEMP. AIR FOR COMBUSTION (This is Reference Temperature) †	F	61
12	TEMPERATURE OF FUEL	F	266
13	GAS TEMP. LEAVING (Boiler) (Econ.) (Air Htr.)	F	400
14	GAS TEMP. ENTERING AH (if conditions to be corrected to guarantee)	F	—

UNIT QUANTITIES

15	ENTHALPY OF SAT. LIQUID (TOTAL HEAT)	Btu/lb	535
16	ENTHALPY OF (SATURATED) (SUPERHEATED) STM	Btu/lb	1194
17	ENTHALPY OF SAT. FEED TO (BOILER) (ECON.) @ 80 °F, P sat.	Btu/lb	48
18	ENTHALPY OF REHEATED STEAM R.H. INLET	Btu/lb	—
19	ENTHALPY OF REHEATED STEAM R. H. OUTLET	Btu/lb	—
20	HEAT ABS/LB OF STEAM (ITEM 16 – ITEM 17)	Btu/lb	1146
21	HEAT ABS/LB R.H. STEAM (ITEM 19 – ITEM 18)	Btu/lb	—
22	DRY REFUSE (ASH PIT + FLY ASH) PER LB AS FIRED FUEL	lb/lb	—
23	Btu PER LB IN REFUSE (WEIGHTED AVERAGE)	Btu/lb	—
24	CARBON BURNED PER LB AS FIRED FUEL	lb/lb	.8542
25	DRY GAS PER LB AS FIRED FUEL BURNED	lb/lb	15.93

HOURLY QUANTITIES

26	ACTUAL WATER EVAPORATED	lb/hr	48,377
27	REHEAT STEAM FLOW	lb/hr	
28	RATE OF FUEL FIRING (AS FIRED wt)	lb/hr	2932
29	TOTAL HEAT INPUT (Item 28 × Item 41)/1000	kB/hr	53694
30	HEAT OUTPUT IN BLOW-DOWN WATER	kB/hr	—
31	TOTAL HEAT OUTPUT ~~(Item 26)(Item 20) + (Item 27)(Item 21) + Item 30 / 1000~~	kB/hr	46852

FLUE GAS ANAL. (BOILER) (ECON) (AIR HTR) OUTLET

32	CO_2	% VOL	13.6
33	O_2	% VOL	2.9
34	CO	% VOL	.003
35	N_2 (BY DIFFERENCE)	% VOL	83.5
36	EXCESS AIR	%	14.9

FUEL DATA

	COAL AS FIRED PROX. ANALYSIS	% wt		OIL	
37	MOISTURE		51	FLASH POINT F*	
38	VOL MATTER		52	Sp. Gravity Deg. API*	
39	FIXED CARBON		53	VISCOSITY AT SSU* BURNER SSF	
40	ASH		44	TOTAL HYDROGEN % wt	10.88
	TOTAL		41	Btu per lb	18310 GROSS
41	Btu per lb AS FIRED				
42	ASH SOFT TEMP.* ASTM METHOD			GAS	% VOL

	COAL OR OIL AS FIRED ULTIMATE ANALYSIS				
43	CARBON	85.42	54	CO	
44	HYDROGEN	10.88	55	CH_4 METHANE	
45	OXYGEN	1.79	56	C_2H_2 ACETYLENE	
46	NITROGEN	0.83	57	C_2H_4 ETHYLENE	
47	SULPHUR	1.05	58	C_2H_6 ETHANE	
40	ASH	0.03	59	H_2S	
37	MOISTURE	0	60	CO_2	
			61	H_2 HYDROGEN	
	TOTAL	100.0		TOTAL	

	COAL PULVERIZATION				
				TOTAL HYDROGEN % wt	
48	GRINDABILITY INDEX*		62	DENSITY 68 F ATM. PRESS.	
49	FINENESS % THRU 50 M*		63	Btu PER CU FT	
50	FINENESS % THRU 200 M*		41	Btu PER LB	

64	INPUT-OUTPUT EFFICIENCY OF UNIT %	ITEM 31 × 100 / ITEM 29	87.3 % *

	HEAT LOSS EFFICIENCY	Btu/lb A.F. FUEL	% of A. F. FUEL
65	HEAT LOSS DUE TO DRY GAS	1296	7.08
66	HEAT LOSS DUE TO MOISTURE IN FUEL	0	0
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2	1186	6.48
68	HEAT LOSS DUE TO COMBUST. IN REFUSE	0	0
69	HEAT LOSS DUE TO RADIATION		0.51
70	UNMEASURED LOSSES		0
71	TOTAL		14.07
72	EFFICIENCY = (100 – Item 71)		85.93 *

$$\boxed{31} = \left\{ \boxed{16} \times \frac{\boxed{9}}{100} + \boxed{15} \times \left[1 - \frac{\boxed{9}}{100}\right] - \boxed{17} \right\} \times \frac{\boxed{26}}{1000}$$

* Not Required for Efficiency Testing

† For Point of Measurement See Par. 7.2.8.1-PTC 4.1-1964

Printed in U.S.A. (10/74)

This Test Form (C-88) may be obtained from ASME, 345 E. 47 St., New York, N.Y. 10017

C.1 (cont'd)

CALCULATION SHEET

ASME TEST FORM FOR ABBREVIATED EFFICIENCY TEST

PTC 4.1-b (1964)
Revised September, 1965

OWNER OF PLANT CHEVRON TEST NO. BOILER NO. 69 DATE 1/7/84

30	HEAT OUTPUT IN BOILER BLOW-DOWN WATER = LB OF WATER BLOW-DOWN PER HR × $\left[\frac{\text{ITEM 15} - \text{ITEM 17}}{1000}\right]$ = 0 kB/hr
34	If impractical to weigh refuse, this item can be estimated as follows DRY REFUSE PER LB OF AS FIRED FUEL = $\frac{\%\text{ ASH IN AS FIRED COAL}}{100 - \%\text{ COMB. IN REFUSE SAMPLE}}$ CARBON BURNED PER LB AS FIRED FUEL = $\frac{\overset{\text{ITEM 43}}{85.42}}{100} - \left[\frac{\overset{\text{ITEM 22}}{0} \times \overset{\text{ITEM 23}}{0}}{14,500}\right]$ = .8542 NOTE: IF FLUE DUST & ASH PIT REFUSE DIFFER MATERIALLY IN COMBUSTIBLE CONTENT, THEY SHOULD BE ESTIMATED SEPARATELY. SEE SECTION 7, COMPUTATIONS.
35	DRY GAS PER LB AS FIRED FUEL BURNED = $\frac{11CO_2 + 8O_2 + 7(N_2 + CO)}{3(CO_2 + CO)}$ × (LB CARBON BURNED PER LB AS FIRED FUEL + $\frac{3}{8}$ S) $= \frac{11 \times \overset{\text{ITEM 32}}{13.6} + 8 \times \overset{\text{ITEM 33}}{2.9} + 7\left(\overset{\text{ITEM 35}}{83.5} + \overset{\text{ITEM 34}}{.003}\right)}{3 \times \left(\overset{\text{ITEM 32}}{13.6} + \overset{\text{ITEM 34}}{.003}\right)} \times \left[\overset{\text{ITEM 24}}{85.42} + \frac{\overset{\text{ITEM 47}}{1.05}}{267}\right] = 15.93$
36	EXCESS AIR† = $100 \times \frac{O_2 - \frac{CO}{2}}{.2682N_2 - (O_2 - \frac{CO}{2})} = 100 \times \frac{\text{ITEM 33} - \frac{\text{ITEM 34}}{2}}{.2682(\text{ITEM 35}) - (\text{ITEM 33} - \frac{\text{ITEM 34}}{2})}$ = 14.9

	HEAT LOSS EFFICIENCY	Btu/lb AS FIRED FUEL	$\frac{\text{LOSS}}{\text{HHV}} \times 100 =$	LOSS %
65	HEAT LOSS DUE TO DRY GAS = LB DRY GAS PER LB AS FIRED FUEL × C_p × $(t_{lvg} - t_{air})$ = $\overset{\text{ITEM 25}}{15.93}$ × 0.24 $\overset{(\text{ITEM 13}) - (\text{ITEM 11})}{(400 - 61)}$ =	1296	$\frac{65}{41}$ × 100 =	7.08
66	HEAT LOSS DUE TO MOISTURE IN FUEL = LB H_2O PER LB AS FIRED FUEL × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = $\frac{\text{ITEM 37}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) − (ENTHALPY OF LIQUID AT T ITEM 11)] =	0	$\frac{66}{41}$ × 100 =	0
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2 = $9H_2$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = 9 × $\frac{\text{ITEM 44}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) − (ENTHALPY OF LIQUID AT T ITEM 11)] = 9 × .1089 × (1240 − 29)	1186	$\frac{67}{41}$ × 100 =	6.48
68	HEAT LOSS DUE TO COMBUSTIBLE IN REFUSE = ITEM 22 × ITEM 23 =		$\frac{68}{41}$ × 100 =	0
69	HEAT LOSS DUE TO RADIATION* = $\frac{\text{TOTAL BTU RADIATION LOSS PER HR}}{\text{LB AS FIRED FUEL} - \text{ITEM 28}}$		$\frac{69}{41}$ × 100 =	0.51
70	UNMEASURED LOSSES **		$\frac{70}{41}$ × 100 =	0
71	TOTAL			14.07
72	EFFICIENCY = (100 − ITEM 71)			85.93

† For rigorous determination of excess air see Appendix 9.2 – PTC 4.1-1964

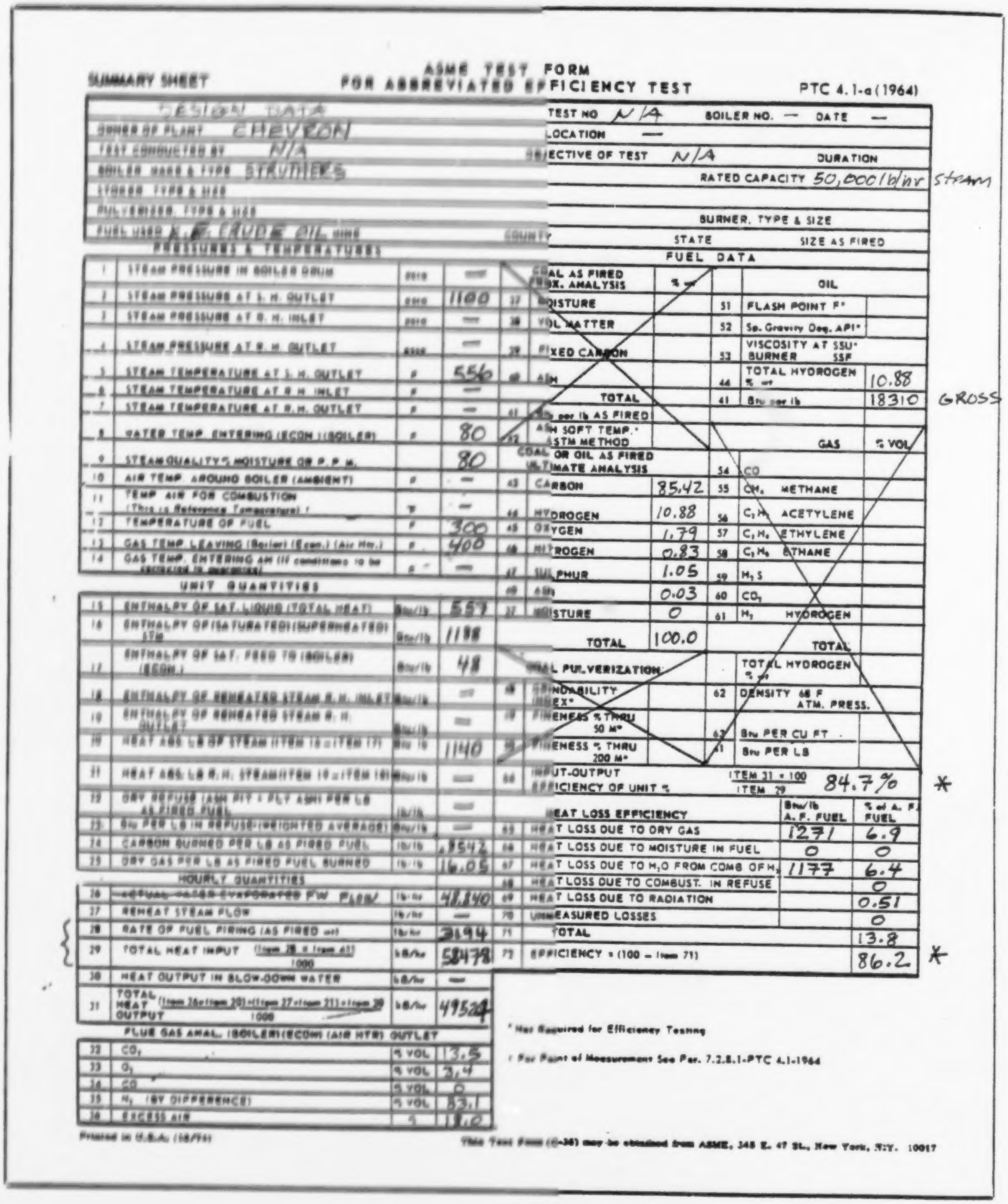
* If losses are not measured, use ABMA Standard Radiation Loss Chart, Fig. 8, PTC 4.1-1964

** Unmeasured losses listed in PTC 4.1 but not tabulated above may be provided for by assigning a mutually agreed upon value for Item 70.

Printed in U.S.A. (10/74)

This Test Form (C-31) may be obtained from ASME, 345 E. 47 St., New York, N.Y. 10017

C.2 Thermal Efficiency Based On Design Data.



SUMMARY SHEET

ASME TEST FORM
FOR ABBREVIATED EFFICIENCY TEST

PTC 4.1-a (1964)

DESIGN DATA	TEST NO N/A BOILER NO. — DATE —
OWNER OF PLANT CHEVRON	LOCATION —
TEST CONDUCTED BY N/A	OBJECTIVE OF TEST N/A DURATION
BOILER MAKE & TYPE STRUTHERS	RATED CAPACITY 50,000 lb/hr STEAM
STOKER TYPE & SIZE	
PULVERIZER, TYPE & SIZE	BURNER, TYPE & SIZE
FUEL USED S.E. CRUDE OIL MINE COUNTY	STATE SIZE AS FIRED

PRESSURES & TEMPERATURES

1	STEAM PRESSURE IN BOILER DRUM	psig	—
2	STEAM PRESSURE AT S.H. OUTLET	psig	1100
3	STEAM PRESSURE AT R.H. INLET	psig	—
4	STEAM PRESSURE AT R.H. OUTLET	psig	—
5	STEAM TEMPERATURE AT S.H. OUTLET	F	556
6	STEAM TEMPERATURE AT R.H. INLET	F	—
7	STEAM TEMPERATURE AT R.H. OUTLET	F	—
8	WATER TEMP. ENTERING (ECON.)(BOILER)	F	80
9	STEAM QUALITY % MOISTURE OR P.P.M.		80
10	AIR TEMP. AROUND BOILER (AMBIENT)	F	—
11	TEMP AIR FOR COMBUSTION (This is Reference Temperature) †	F	—
12	TEMPERATURE OF FUEL	F	300
13	GAS TEMP. LEAVING (Boiler) (Econ.) (Air Htr.)	F	400
14	GAS TEMP. ENTERING AH (If conditions to be corrected to guarantee)	F	—

UNIT QUANTITIES

15	ENTHALPY OF SAT. LIQUID (TOTAL HEAT)	Btu/lb	557
16	ENTHALPY OF (SATURATED) (SUPERHEATED) STM.	Btu/lb	1188
17	ENTHALPY OF SAT. FEED TO (BOILER) (ECON.)	Btu/lb	48
18	ENTHALPY OF REHEATED STEAM R.H. INLET	Btu/lb	—
19	ENTHALPY OF REHEATED STEAM R.H. OUTLET	Btu/lb	—
20	HEAT ABS/LB OF STEAM (ITEM 16 – ITEM 17)	Btu/lb	1140
21	HEAT ABS/LB R.H. STEAM (ITEM 19 – ITEM 18)	Btu/lb	—
22	DRY REFUSE (ASH PIT + FLY ASH) PER LB AS FIRED FUEL	lb/lb	—
23	Btu PER LB IN REFUSE (WEIGHTED AVERAGE)	Btu/lb	—
24	CARBON BURNED PER LB AS FIRED FUEL	lb/lb	.8542
25	DRY GAS PER LB AS FIRED FUEL BURNED	lb/lb	16.05

HOURLY QUANTITIES

26	~~ACTUAL WATER EVAPORATED~~ FW FLOW	lb/hr	43,440
27	REHEAT STEAM FLOW	lb/hr	—
28	RATE OF FUEL FIRING (AS FIRED wt)	lb/hr	3194
29	TOTAL HEAT INPUT (Item 28 × Item 41) / 1000	kB/hr	58478
30	HEAT OUTPUT IN BLOW-DOWN WATER	kB/hr	—
31	TOTAL HEAT OUTPUT (Item 26)(Item 20)+(Item 27)(Item 21)+Item 30 / 1000	kB/hr	49524

FLUE GAS ANAL. (BOILER)(ECON)(AIR HTR) OUTLET

32	CO_2	% VOL	13.5
33	O_2	% VOL	3.4
34	CO	% VOL	0
35	N_2 (BY DIFFERENCE)	% VOL	83.1
36	EXCESS AIR	%	18.0

FUEL DATA

	COAL AS FIRED PROX. ANALYSIS	% wt		OIL	
37	MOISTURE		51	FLASH POINT F*	
38	VOL MATTER		52	Sp. Gravity Deg. API*	
39	FIXED CARBON		53	VISCOSITY AT SSU* BURNER SSF	
40	ASH		44	TOTAL HYDROGEN % wt	10.88
	TOTAL		41	Btu per lb	18310 GROSS
41	Btu per lb AS FIRED				
42	ASH SOFT TEMP.* ASTM METHOD			GAS	% VOL
	COAL OR OIL AS FIRED ULTIMATE ANALYSIS		54	CO	
43	CARBON	85.42	55	CH_4 METHANE	
44	HYDROGEN	10.88	56	C_2H_2 ACETYLENE	
45	OXYGEN	1.79	57	C_2H_4 ETHYLENE	
46	NITROGEN	0.83	58	C_2H_6 ETHANE	
47	SULPHUR	1.05	59	H_2S	
48	ASH	0.03	60	CO_2	
37	MOISTURE	0	61	H_2 HYDROGEN	
	TOTAL	100.0		TOTAL	
	COAL PULVERIZATION			TOTAL HYDROGEN % wt	
48	GRINDABILITY INDEX*		62	DENSITY 68 F ATM. PRESS.	
49	FINENESS % THRU 50 M*		63	Btu PER CU FT	
50	FINENESS % THRU 200 M*		41	Btu PER LB	

64	INPUT-OUTPUT EFFICIENCY OF UNIT %	ITEM 31 × 100 / ITEM 29	84.7% *

	HEAT LOSS EFFICIENCY	Btu/lb A. F. FUEL	% of A. F. FUEL
65	HEAT LOSS DUE TO DRY GAS	1271	6.9
66	HEAT LOSS DUE TO MOISTURE IN FUEL	0	0
67	HEAT LOSS DUE TO H_2O FROM COMB OF H_2	1177	6.4
68	HEAT LOSS DUE TO COMBUST. IN REFUSE		0
69	HEAT LOSS DUE TO RADIATION		0.51
70	UNMEASURED LOSSES		0
71	TOTAL		13.8
72	EFFICIENCY = (100 – Item 71)		86.2 *

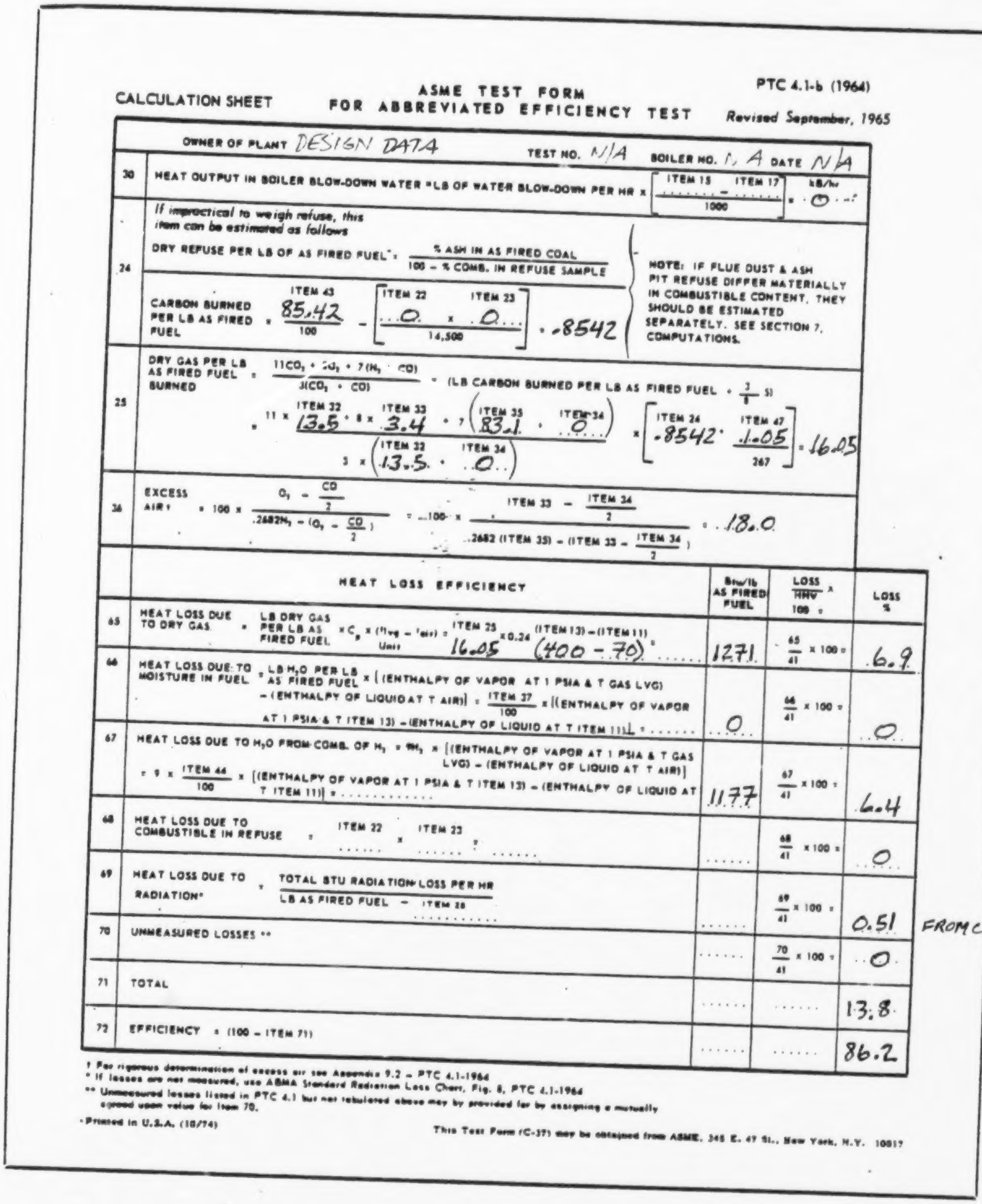
* Not Required for Efficiency Testing

† For Point of Measurement See Par. 7.2.8.1-PTC 4.1-1964

Printed in U.S.A. (10/74)

This Test Form (C-36) may be obtained from ASME, 345 E. 47 St., New York, N.Y. 10017

C.2 (cont'd)



CALCULATION SHEET

ASME TEST FORM
FOR ABBREVIATED EFFICIENCY TEST

PTC 4.1-b (1964)
Revised September, 1965

OWNER OF PLANT DESIGN DATA TEST NO. N/A BOILER NO. N A DATE N/A

30 HEAT OUTPUT IN BOILER BLOW-DOWN WATER = LB OF WATER BLOW-DOWN PER HR × $\left[\frac{\text{ITEM 15} - \text{ITEM 17}}{1000}\right]$ = 0 kB/hr

24 *If impractical to weigh refuse, this item can be estimated as follows*

DRY REFUSE PER LB OF AS FIRED FUEL* = $\frac{\%\ \text{ASH IN AS FIRED COAL}}{100 - \%\ \text{COMB. IN REFUSE SAMPLE}}$

CARBON BURNED PER LB AS FIRED FUEL = $\frac{\overset{\text{ITEM 43}}{85.42}}{100} - \left[\frac{\overset{\text{ITEM 22}}{0} \times \overset{\text{ITEM 23}}{0}}{14{,}500}\right]$ = .8542

NOTE: IF FLUE DUST & ASH PIT REFUSE DIFFER MATERIALLY IN COMBUSTIBLE CONTENT, THEY SHOULD BE ESTIMATED SEPARATELY. SEE SECTION 7, COMPUTATIONS.

25 DRY GAS PER LB AS FIRED FUEL BURNED = $\frac{11CO_2 + 8O_2 + 7(N_2 + CO)}{3(CO_2 + CO)} \times \left(\text{LB CARBON BURNED PER LB AS FIRED FUEL} + \frac{3}{8}S\right)$

$= \frac{11 \times \overset{\text{ITEM 32}}{13.5} + 8 \times \overset{\text{ITEM 33}}{3.4} + 7\left(\overset{\text{ITEM 35}}{83.1} + \overset{\text{ITEM 34}}{0}\right)}{3 \times \left(\overset{\text{ITEM 32}}{13.5} + \overset{\text{ITEM 34}}{0}\right)} \times \left[\overset{\text{ITEM 24}}{.8542} + \frac{\overset{\text{ITEM 47}}{1.05}}{267}\right] = 16.05$

26 EXCESS AIR† = $100 \times \frac{O_2 - \frac{CO}{2}}{.2682N_2 - \left(O_2 - \frac{CO}{2}\right)} = 100 \times \frac{\text{ITEM 33} - \frac{\text{ITEM 34}}{2}}{.2682(\text{ITEM 35}) - \left(\text{ITEM 33} - \frac{\text{ITEM 34}}{2}\right)}$ = 18.0

	HEAT LOSS EFFICIENCY	Btu/lb AS FIRED FUEL	LOSS/HHV × 100 =	LOSS %
65	HEAT LOSS DUE TO DRY GAS = LB DRY GAS PER LB AS FIRED FUEL × C_p × ($t_{lvg} - t_{air}$) = ITEM 25 16.05 × 0.24 (ITEM 13) − (ITEM 11) (400 − 70) =	1271	$\frac{65}{41}$ × 100 =	6.9
66	HEAT LOSS DUE TO MOISTURE IN FUEL = LB H_2O PER LB AS FIRED FUEL × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = $\frac{\text{ITEM 37}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) − (ENTHALPY OF LIQUID AT T ITEM 11)] =	0	$\frac{66}{41}$ × 100 =	0
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2 = $9H_2$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = 9 × $\frac{\text{ITEM 44}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) − (ENTHALPY OF LIQUID AT T ITEM 11)] =	1177	$\frac{67}{41}$ × 100 =	6.4
68	HEAT LOSS DUE TO COMBUSTIBLE IN REFUSE = ITEM 22 × ITEM 23 =		$\frac{68}{41}$ × 100 =	0
69	HEAT LOSS DUE TO RADIATION* = $\frac{\text{TOTAL BTU RADIATION LOSS PER HR}}{\text{LB AS FIRED FUEL} - \text{ITEM 28}}$		$\frac{69}{41}$ × 100 =	0.51 FROM CHART
70	UNMEASURED LOSSES **		$\frac{70}{41}$ × 100 =	0
71	TOTAL			13.8
72	EFFICIENCY = (100 − ITEM 71)			86.2

† For rigorous determination of excess air see Appendix 9.2 − PTC 4.1-1964

* If losses are not measured, use ABMA Standard Radiation Loss Chart, Fig. 8, PTC 4.1-1964

** Unmeasured losses listed in PTC 4.1 but not tabulated above may by provided for by assigning a mutually agreed upon value for Item 70.

Printed in U.S.A. (10/74)

This Test Form (C-37) may be obtained from ASME, 345 E. 47 St., New York, N.Y. 10017

APPENDIX D - 30-day Test

The 30-day continuous emissions monitoring test was performed by Acurex Corporation. All information available at the time this report was prepared is presented in this Appendix.

ACUREX Corporation

3382

Energy & Environmental Division

January 3, 1984

Glenn England
Energy and Environmental Research Corp.
18 Mason St.
Irvine, CA 92714

Dear Glenn:

In response to your request to Bob Hall regarding our test plan for the Chevron low-NO_x EOR facility I have listed our tentative sampling protocol and outlined a tentative schedule. As you know our test program will consist of two parts: a 30-day test to continuously monitor flue gas emissions and an in-depth one-day test for measurements of organic and inorganic pollutants. The actual sampling protocol during the in-depth testing will most likely consist of the following:

- Source Assessment Sampling System (SASS) for semivolatile organic and inorganic species
- Volatile Organic Sampling Train (VOST) for volatile organic species
- EPA Method 5 for total particulate
- Controlled Condensation System (CCS) for SO_2/SO_3 emissions
- On-site gas chromatography of flue gas grab samples for C_1 to C_6 hydrocarbons
- Grab sample of flue gas for off-site N_2O analysis

In addition to these measurements, a sample of the fuel oil will be obtained for ultimate and trace element analyses.

Figure 1 illustrates our tentative schedule. We plan to initiate the 30-day continuous monitoring test on January 6, 1984 to overlap with the EERC emissions work. The time frame for the in-depth testing has not been firmed up yet, however it is now set tentatively for the last week of January.

I hope this answers the questions you had regarding our test protocol. Give me a call if you need further clarification.

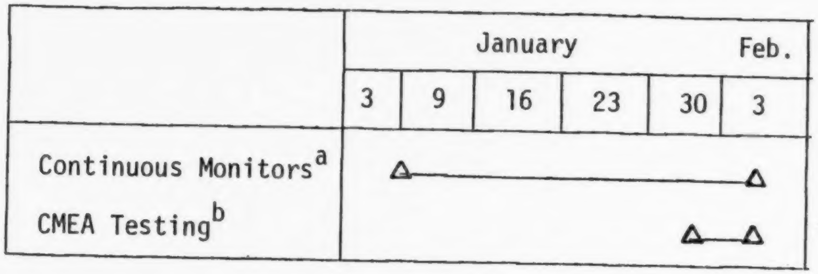
Sincerely,

Larry R. Waterland
Project Manager

LRW/sla

555 Clyde Avenue, P.O. Box 7555, Mountain View, CA 94039 (415) 964-3200 Telex: 34-6391 TWX: 910-7796593

Figure 1. Test Schedule



[a] Continuous monitors for O_2, CO_2, CO, NO/NO_x, SO_2 and TUHC

[b] In-depth testing for criteria and noncriteria emissions

ACUREX
Corporation

3563

Energy & Environmental Division

May 2, 1984

Mr. Glenn England
Energy and Environmental Research Corporation
18 Mason
Irvine, CA 92714

Dear Glenn:

Enclosed find an excerpt of the MPR for our project with Bob Hall under which we tested the Chevron steamer. The excerpt enclosed discusses the Method 5 particulate, the SASS particulate, the Method 8 sulfur oxide, and the VOST data obtained from tests performed on February 1. Also, enclosed find a figure which summarizes the Anderson particle sizing results obtained in impactor train tests performed on February 22. The Anderson runs suggest a mean emitted particle size (d_{50}) of 0.056 (run 1) to 0.14 (run 2) µm, or 90 percent less 1.4 (run 1) to 11 (run 2) µm. Total particulate catch in the Anderson was 0.013 (run 1) and 0.017 (run 2) gr/dscf. These should be compared to the Method 5 solid (front half) or SASS solid particulate measurements, although we ran in-stack impactor trains, so collection temperatures were high (555°F for run 1 and 530°F for run 2).

SASS train total organic and semivolatile organic species analysis and controlled condensation train analyses have been completed, though we haven't reduced the results yet. This will happen in the next week or so and I will forward these along to you when they're legible.

The thirty-day monitoring data are merely a raw data file right now, waiting to be massaged. I hope to be able to devote some attention to this next week. I'll send plots to you as soon as I get them, but I don't expect this to happen until the week of May 21.

Please be advised that all the data I'm sending is draft data, subject to reinterpretation or refining. However, I don't expect much, if anything, will change.

I hope the enclosed is a start toward the information you hope to receive. If you have any questions, don't hesitate to have me a call.

Sincerely yours,

Larry R. Waterland
Project Engineer

attach.

555 Clyde Avenue, P.O. Box 7555, Mountain View, CA 94039 (415) 964-3200 Telex: 34-6391 TWX: 910-7796593

Monthly Progress Report 7600/7733-50 for the Period:
February 1, 1984 to February 29, 1984

COMBUSTION MODIFICATION ENVIRONMENTAL ASSESSMENT

March 23, 1984

PRELIMINARY DATA
SUBJECT TO REVISION;
NOT TO BE DISTRIBUTED OR REFERENCED
(Reproduced w/permission)

Project 7600/7733
Contract No. 68-02-3188

For

U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

By

Acurex Corporation
Energy & Environmental Division
555 Clyde Avenue
P.O. Box 7555
Mountain View, California 94039

Approved by: for
H. B. Mason
Project Manager

2.2 Task 2: Application Testing and Environmental Assessment

Comprehensive (SASS, VOST, Method 5/8, and flue gas grab sampling for N_2O and C_1 to C_6 hydrocarbon emission) testing of the enhanced oil recovery (EOR) steam generator equipped with the EPA/EER low-NO_x burner was performed as scheduled on February 1. The tests went essentially according to the test plan. However, due to equipment problems, no controlled condensation system (CCS) measurement was made. Thus only Method 8 sulfur species emission results will be available for the comprehensive test period. CCS measurements were rescheduled as noted below.

Table 1 summarizes flue gas emissions measured during the comprehensive test period. Corresponding steamer operating data are noted in table 2. As

Table 1. Flue Gas Continuous Monitor Readings Over the SASS Test: EOR Steam Generator Tests

DAILY

	As Measured		Average at 3 percent O_2
	Range	Average	
O_2 (percent, dry)	2.3 to 2.8	2.7	--
CO_2 (percent, dry)	12.2 to 13.7	13.1	--
CO (ppm, dry)	21 to 27	24	24
NO_x (ppm, dry)	66 to 75	70	69
SO_2 (ppm, dry)	560 to 579	565	556

Table 2. Steamer/Burner Operating Data Over the SASS Test: EOR Steam Generator Tests

	Range	Average
Fuel flow, gal/min	--	6.18
bbl/day	--	212
10^6 Btu/hr	--	55.3[a]
Fuel temperature, °F	264 to 269	266
Feedwater flow, gal/min	99 to 105	102[b]
10^3 bbl/day	3.4 to 3.6	3.5[b]
Steam pressure, psig	1,020 to 1,290	1,120[b]
Steam temperature, °F	535 to >570	--
Burner primary air flow, scfm	5,900 to 6,080	5,990
Secondary air flow, scfm	5,040 to 5,650	5,420

[a] Based on 18,310 Btu/lb, API Gravity 13.2 for Kern Front Crude received from EER

[b] Average misleading, step variable change including through SASS test

shown, flue NO_x emissions were less than 75 ppm, with an average of 70 ppm. CO emissions were less than 27 ppm with an average of 24 ppm. These readings are well below the design goals for the burner of 85 ppm (3 percent O_2) NO_x at less than 45 ppm (3 percent O_2) CO. Table 2 notes that steamer heat input (55 million Btu/hr) was at rated.

Two Method 5/8 runs were performed on the test day. The Method 8 impingers, in addition to being analyzed for SO_2/SO_3, were also analyzed by the old condensibles (back half) Method 5 procedure, to give a condensible particulate emission value. This was done at the request of the host site; the local environmental regulatory agency still requires both solid and condensible particulate to be determined from sources under its pureview. Table 3 shows results of the Method 5 measurements, along with steamer operating data over each Method 5 run.

As shown in table 3, total particulate emissions for both runs were comparable (0.062 and 0.065 gr/dscf). This is in the range typical for uncontrolled EOR steamer emissions. However, the split between solid and condensible particulate between the two runs changed significantly. For run 1 only about 43 percent of the Method 5 catch was solid particulate (57 percent condensibles); for run 2 90 percent was solid particulate (10 percent condensibles). For comparison, the SASS solid particulate result was 26 mg/dscm (0.011 gr/dscf). However, the SASS filter is maintained at a higher temperature (450°F) than the Method 5 filter (250°F). Consequently some condensible matter which might be caught on a Method 5 filter would escape a SASS filter. In addition the SASS protocol is a single point sampling procedure, inherently less accurate than the multipoint traverse specified by Method 5.

Table 3. Flue Gas Particulate Measurement Results: EOR Steam Generator Tests

	Run 1		Run 2	
	mg/dscm	gr/dscf	mg/dscm	gr/dscf
Method 5				
Solid (front half)	64	0.028	128	0.056
Condensible (back half)	85	0.037	14	0.006
Total	149	0.065	142	0.062
Steamer Operating Data	Range	Average	Range	Average
Fuel flow, gal/min	--	6.38	--	6.37
bbl/day	--	219	--	218
10^6 Btu/hr	--	57.1	--	57.0
Fuel temperature, °F	264 to 268	266	266 to 268	267
Feedwater flow, gal/min	105	105	99	99
10^3 bbl/day	3.6	3.6	3.4	3.4
Steam pressure, psig	1,020	1,020	1,320	1,320
Steam temperature, °F	535	535	>570	>570
Burner primary air flow, scfm	5,900 to 6,080	6,000	5,740 to 6,080	5,880
Secondary air flow, scfm	5,360 to 5,590	5,460	5,390 to 6,260	6,000
Stack temperature, °F	450 to 466	456	472 to 490	479

The operating data in table 3 show that two operational changes occurred between the two runs. Steam pressure (thus temperature) was increased in run 2, though fuel flow was held constant. Feedwater flow was, therefore, reduced slightly to maintain steam quality. The net result of this change was slightly higher stack temperature (less heat absorption in the convection section of the steamer) for run 2. In addition, burner primary air flow was slightly lower in run 2, and secondary air flow higher. However, neither of these operating changes would, of themselves, be expected to affect the solid to condensible particulate ratio.

Table 4 shows results of the Method 8 analyses for the two Method 5/8 runs. For comparison, the average SO_2 continuous monitor reading over each run is also noted. The agreement between the reference method and the SO_2 monitor was within 10 percent for run 1 and 3 percent for run 2. The SO_2 levels measured (560 to 620 ppm dry at 3 percent O_2) are as would be expected from a 1 percent sulfur crude oil, such as the Kern Front crude fired. Interestingly, the ratio of SO_3 to total SO_x at between 0.7 percent (run 2) and 2.0 percent (run 1) is much lower than the range typical for oil-fired sources (5 to 10 percent). This ratio is more in the range typical for coal-fired sources (less than 2 percent).

Table 5 shows analysis results of the VOST train samples obtained during the comprehensive tests. As noted in the table, only benzene, toluene, and perhaps ethylbenzene were present in the stack gas discharge at 18 ppb or less levels. This is consistent with expectations and other VOST data obtained to date from external combustion sources.

Analyses of SASS train samples were initiated in February. First round organic analyses (TCO, GRAV, IR, and GC/MS of total extracts) are expected to

Table 4. Sulfur Species Emissions: EOR Steam Generator Tests

	Run 1	Run 2
Method 8		
SO_2, ppm dry, 3 percent O_2	619	593
SO_3, ppm dry, 3 percent O_2	12.9	4.4
Continuous monitor		
SO_2, ppm dry, 3 percent O_2	557	574

Table 5. Volatile Organic Species Emissions: EOR Steam Generator Tests

Compound[a]	Stack Gas Concentration[b]				
	Run 1 (μg/dscm)	Run 2 (μg/dscm)	Run 3 (μg/dscm)	Average (μg/dscm)	(ppb)
Benzene	128	42	9	60	18
Toluene	6.3	1.1	2.3	3.2	0.83
Ethylbenzene	3.2	<1	<1	1.7	0.39

[a] Chloromethane, bromomethane, vinyl chloride, chloroethane, methylene chloride, chloroform, 1,1-dichloroethylene, 1,1-dichloroethane, 1,2-dichloroethane, t-1,2-dichloroethylene, 1,1,1-trichloroethane, trichloroethylene, carbon tetrachloride, dichlorobromomethane, 1,2-dichloropropane, t-1,3-dichloropropene, chlorodibromomethane, 1,1,2-trichloroethane, c-1,3-dichloropropene, 2-chloroethyl vinyl ether, bromoform, 1,1,2,2-tetrachloroethane, tetrachloroethylene, chlorobenzene, xylenes, allyl chloride, ethylene oxide, propylene oxide, and 2-nitropropane were also analyzed for and not detected above a blank corrected detection limit of 1.0 μg/dscm

[b] Mean (field, trip, and laboratory) blank corrected

be complete in March. First round inorganic (SSMS) analyses are scheduled to be complete in April.

As noted in the January MPR, the 30-day continuous emission monitoring period for the steamer began January 19. Method 7 NO_x monitor certification tests were performed on January 24 and February 8. Plans were to continue monitoring until February 17, with the third NO_x monitor certification test performed on February 16, and CCS measurements (to make up for not performing these during the comprehensive test day) performed on February 15. In addition, host site personnel expressed great interest in having particle size distribution measurements made. It was agreed that these would be performed, and were scheduled for February 14.

However, the steamer was taken down on February 12 to allow watertube inspection (some concerns relating to accelerated tube corrosion had been raised, these turned out to be unfounded), and was not brought online again until February 15. Then on February 16 site electrical problems caused the unit to trip. It was not brought back to steady operation until late in the day on February 21. As a consequence of these problems, the continuous monitoring period extended through February 24. Three Anderson impactor (particle sizing) train runs were made February 22. Two CCS measurements were made February 23, and the final Method 7 NO_x monitor certification test was performed on February 24.

ACUREX
Corporation

Energy & Environmental Division

LRW3597

June 4, 1984

Glenn England
Energy & Environmental Research Corporation
18 Mason
Irvine, CA 92714

Dear Glenn:

Enclosed find an excerpt of the April MPR for our project with Bob Hall under which we tested the Chevron Steamer. This excerpt discusses the particle sizing results (which I ran through in my letter to you of May 2), the controlled condensation system results, and the SASS train organic analysis results. Again, please treat these results as draft data.

I haven't been able to tackle 30-day monitoring data yet, and don't foresee getting to it in the very near future. So, I expect that the enclosed will wrap up all of our information for including in your draft report to Mike Osborne. I hope the enclosed is in time for this. If you have any questions, please give me a call.

Sincerely yours,

Larry R. Waterland
Project Engineer

LRW/sla

Encl.

555 Clyde Avenue, P.O. Box 7555, Mountain View, CA 94039 (415) 964-3200 Telex: 34-6391 TWX: 910-7796593

Monthly Progress Report 7600/7733-52 for the Period:
April 1, 1984 to April 30, 1984

COMBUSTION MODIFICATION ENVIRONMENTAL ASSESSMENT

May 11, 1984

Project 7600/7733
Contract No. 68-02-3188

For

U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

By

Acurex Corporation
Energy & Environmental Division
555 Clyde Avenue
P.O. Box 7555
Mountain View, California 94039

Approved by: H. B. Mason

H. B. Mason
Project Manager

2.1 Task 2: Application Testing and Environmental Assessment

Efforts in April focused on continuing analyses of samples collected in tests of the enhanced oil recovery (EOR) steam generator retrofitted with the EPA/EER low-NO_x burner.

Evaluation of data obtained from the laboratory efforts required for the Anderson particle size distribution trains, the controlled condensation system trains, and the Method 7 NO_x monitor certification tests performed during the last week of steamer monitoring was completed in April. Results of the particle size distribution (Anderson) measurements made on February 22 are shown in figure 2. As noted in the figure, the particle size distribution for both runs was log-normal (as evidenced by the straight curve fits). Mean particle size (d_{50}) was 0.056 (run 1) to 0.14 (run 2) μm; or 90 percent of the emitted particulate was less than 1.4 (run 1) to 11 (run 2) μm. Table 1 notes the total flue gas particulate loading measured using the Anderson trains.

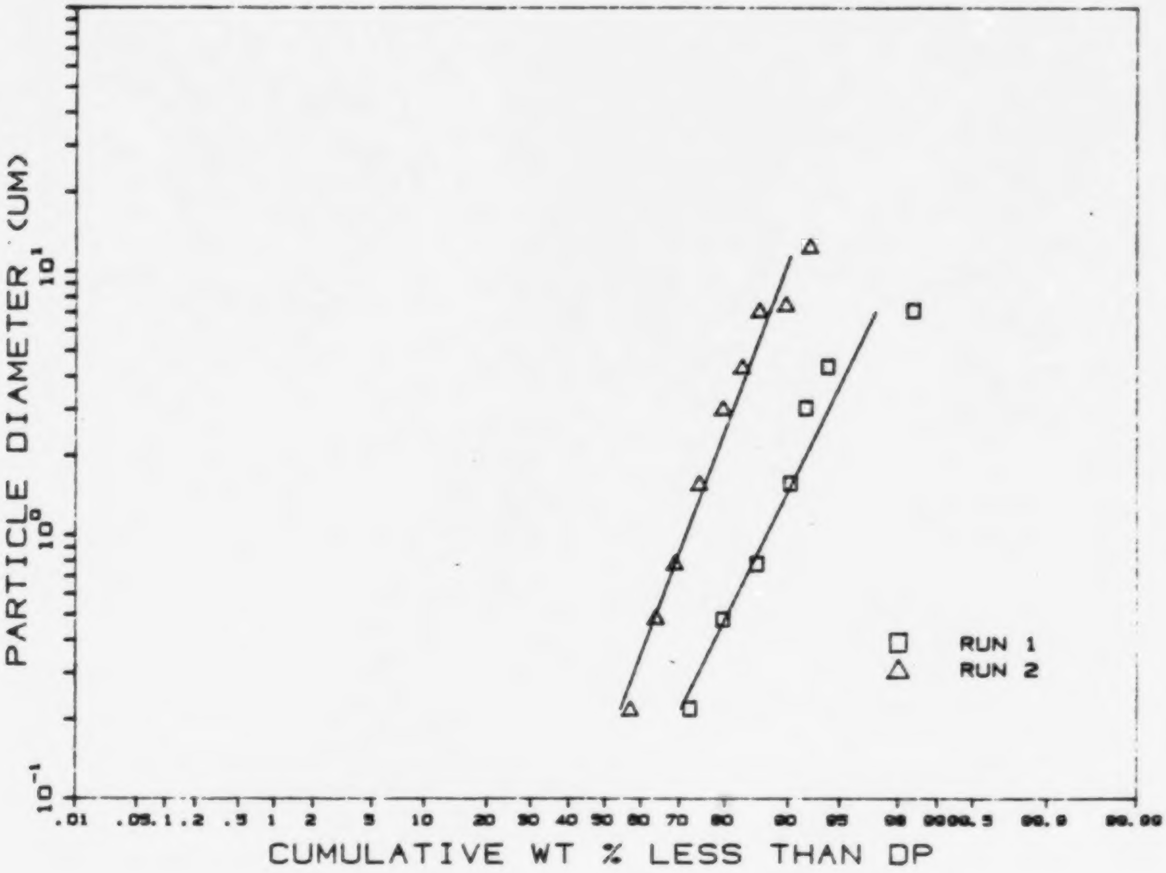


Figure 2. Particle Size Distribution: EOR Steamer/Low-NO_x Burner Tests

Table 1. Particulate Loading: EOR Steamer/Low-NO_x Burner Tests

Method	Date	Particulate Load (mg/dscm)	Collection Temperature (°F)
Anderson Impactor			
Run 1: Solid Particulate	2/22/84	30.8	550[a]
Run 2: Solid Particulate	2/22/84	38.2	530[a]
SASS			
Solid Particulate	2/1/84	26	450[b]
Method 5			
Run 1: Solid Particulate	2/1/84	64	250[b]
Condensible Particulate		85	
Total		149	
Run 2: Solid Particulate	2/1/84	128	250[b]
Condensible Particulate		14	
Total		142	

[a] Stack temperature (in-stack impactor train)
[b] Filter oven nominal temperature

Analogous results from the Method 5 and the SASS runs performed on February 1, and as reported in the February MPR, are noted for comparison. Interestingly, the Anderson results compare quite well with the SASS measurement. However both are significantly less than the method solid (front half) result. The solid particulate collection temperature for each method is also noted in table 1 (stack temperature for the in-stack Anderson impactors and filter oven temperature for SASS and Method 5). The relatively good agreement between SASS and Anderson particulate load is consistent with the similar high temperatures at which solid particulate is collected in these methods. The high Method 5 solid particulate results suggested that significant quantities of material condense in the temperature range from 250 to 450°F.

Controlled condensation system (CCS) results for measurements made February 23 are given in table 2. The table also notes the average SO_2 monitor reading over the appropriate run/test period. (The monitors were inoperative for run 2.) Agreement between the SO_2 monitor and the CCS SO_2 results is within 7 percent. The fraction of sulfur oxides emitted as SO_3 ($SO_3/(SO_2 + SO_3)$), at 7.2 to 7.7 percent is in the range typical of crude oil fired sources. However, these results differ from those obtained using Method 8 (see the February MPR). SO_3 emissions measured by Method 8 were significantly lower.

Table 2. Controlled Condensation System Emission Results: EOR Steamer/Low-NO_x Burner Tests

	Run 1	Run 2
Controlled Condensation System (2/23/84)		
SO_2, ppm dry	602	611
SO_3, ppm dry	47	51
Continuous Monitors		
SO_2, ppm dry	642	--[a]
O_2, percent dry	4.4	--

[a] --: monitors inoperative

First round organic analyses of SASS train samples collected during testing of the steamer on February 1 have also been completed. Total organic results are shown in table 5. As noted, total organic emissions from the unit were quite low.

Table 6 shows emission levels of the semivolatile organic priority pollutant species detected in the XAD-2 extracts from the SASS train for the steamer tests. Duplicate injections were performed as indicated. As noted, low levels of naphthalene and phenol were found. The dimethyl phthalate noted is most likely a sample contaminant.

As part of quality assurance procedures performed in the EOR steamer test program, a sample of blank XAD-2 resin was spiked with a mixture of TCO compounds (dodecane and hexadecane), polynuclear aromatic hydrocarbons (naphthalene, phenanthrene, and pyrene), and GRAV compounds (bis(2-ethylhexyl) phthalate, plus the phenanthrene and pyrene noted). This spiked resin was then extracted and analyzed as a separate sample to obtain recovery information. Table 7 summarizes this recovery information. As shown in the table, the recovery and analytical accuracy for all components spiked was excellent.

Since, as noted in table 5, the total organic content of the EOR steamer test samples did not exceed liquid chromatography or low resolution mass spectrometry trigger levels, these will not be performed. Organic analyses for this test are therefore complete. Only inorganic analyses remain to be completed for this test.

Table 5. Total Organic Emission Results: EOR Steamer/Low-NO_x Burner Tests

Sample	Total Semivolatile Organics (TCO)	Total Nonvolatile Organics (GRAV)	Total Organics	
			mg	mg/dscm
Filter particulate	--[a]	<3	<3	<0.1
XAD-2 + OMC extract[b]	3.8	3	7	0.3
Total flue gas	3.8	3	7	0.3

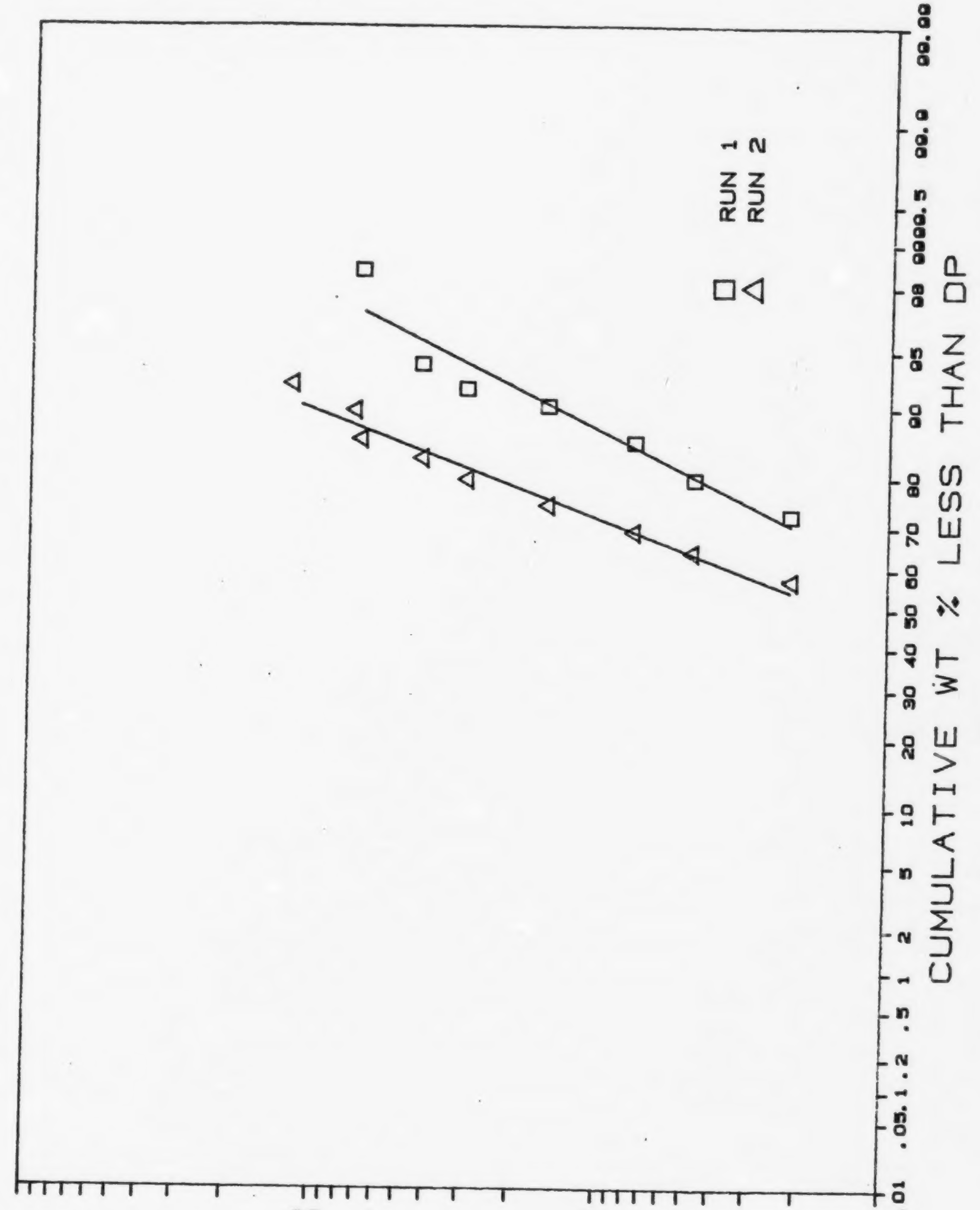
[a] TCO not performed; sample collected at high temperature
[b] Field blank corrected

Table 6. Semivolatile Organic Priority Pollutant Emissions: EOR Steamer/Low-NO_x Burner Tests

Compound	Run 1 (μg)	Run 2 (μg)	Average	
			μg	μg/dscm
Dimethylphthalate	100	60	80	3.6
Naphthalene	40	20	30	1.4
Phenol	20	10	15	0.7

Table 7. Spiked XAD-2 Resin Analysis Results

Analyte Spiked	Spiked Amount (mg)	Recovered Amount (mg)	Percent Recovery
TCO compounds			
(400 μg dodecane, 400 μg hexadecane)	0.800	0.784	98
GRAV compounds			
(10 mg bis(2-ethylhexyl) phthalate, 400 μg naphthalene, 400 μg phenanthrene)	10.8	11.0	102
Polynuclear aromatics			
Naphthalene	0.40	0.42	105
Phenanthrene	0.40	0.40	100
Pyrene	0.40	0.51	128



PARTICLE DIAMETER (UM)
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10^{0}
10^{1}
CUMULATIVE WT % LESS THAN DP
.01
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.1
.2
.5
1
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5
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90
95
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99
99.5
99.8
99.9
99.99
□ RUN 1
△ RUN 2

Table 3 summarizes the results of the Method 7 NO_x monitor certification test performed of February 8. Corresponding results from the abbreviated test performed on February 24 (only three sets of three flasks were taken during the abbreviated test) are shown in table 4. The relative accuracy of the monitor as determined by the abbreviated certification test of February 24 was within the performance specification of 20 percent. The relative accuracy as determined by the tests on February 8 was not. However, the first set of three flasks taken (run 1) gave atypically low analysis results. If this run is removed as an outlier, then the meter relative accuracy is determined by the test decreases to 15 percent, within the performance specification.

Table 3. Method 7 NO_x Monitor Certification Test Results: EOR Steamer, February 8, 1984

Run	Method 7 Result (ppm)				NO_x Monitor (ppm)	Difference (ppm)
	1st Sample	2nd Sample	3rd Sample	Average		
1	50	32	24	36	69	33
2	80	100	64	81	72	(9)
3	64	72	62	66	70	4
4	82	95	96	91	75	(16)
5	84	16	80	60	61	1
6	80	13	88	60	65	5
7	88	63	54	68	78	10
8	59	60	54	58	68	10
9	41	63	--[a]	52	63	11
			Mean	64		11

95 percent C.I. of the difference = 7.2

$$\text{Relative Accuracy} = \frac{11 + 7.2}{64} = 28 \text{ percent}$$

[a] Sample lost during recovery

Table 4. Method 7 NO_x Monitor Certification Test Results: EOR Steamer, February 24, 1984

Run	Method 7 Result (ppm)				NO_x Monitor (ppm)	Difference (ppm)
	1st Sample	2nd Sample	3rd Sample	Average		
1	65	55	53	58	68	10
2	70	72	99	81	73	(8)
3	75	33	63	57	67	10
			Mean	65		9.3

95 percent C.I. of the difference = 2.9

$$\text{Relative Accuracy} = \frac{2.9 + 9.3}{65} = 19 \text{ percent}$$

LOW-NO_X TEOR BURNER SYSTEM

EMISSIONS CHARACTERIZATION

TEOR AD HOC COMMITTEE MEETING 2/6/84

ACUREX
Corporation

TEST PLAN

- THIRTY-DAY CONTINUOUS MONITORING
  - -- JANUARY 19, 1984 TO FEBRUARY 17, 1984
  - -- CONTINUOUS MONITORS: NO_x, CO, CO_2, O_2, SO_2
  - -- SMOKE SPOT (DAILY)
  - -- STEAMER/BURNER OPERATING DATA (HOURLY)
  - -- METHOD 7 MONITOR CERTIFICATION, THREE TIMES
- COMPREHENSIVE TESTING
  - -- FEBRUARY 1, 1984

COMPREHENSIVE TESTING

TEST PLAN

- SOURCE ASSESSMENT SAMPLING SYSTEM (SASS)
  - -- FLUE GAS ORGANICS
    - TOTAL SEMIVOLATILE (C_7-C_{16})
    - TOTAL NONVOLATILE (C_{16+})
    - SEMIVOLATILE PRIORITY POLLUTANTS (POM'S, ETC.)
  - -- 73 TRACE ELEMENTS
    - PARTICULATE
    - VAPOR (450°F)

- VOLATILE ORGANIC SAMPLING TRAIN (VOST)
  - -- VOLATILE ORGANIC·PRIORITY POLLUTANTS (BENZENE, TOLUENE, ETHYLBENZENE, ETC.)

- METHOD 5/8
  - -- TOTAL PARTICULATE
  - -- SO_2, SO_3

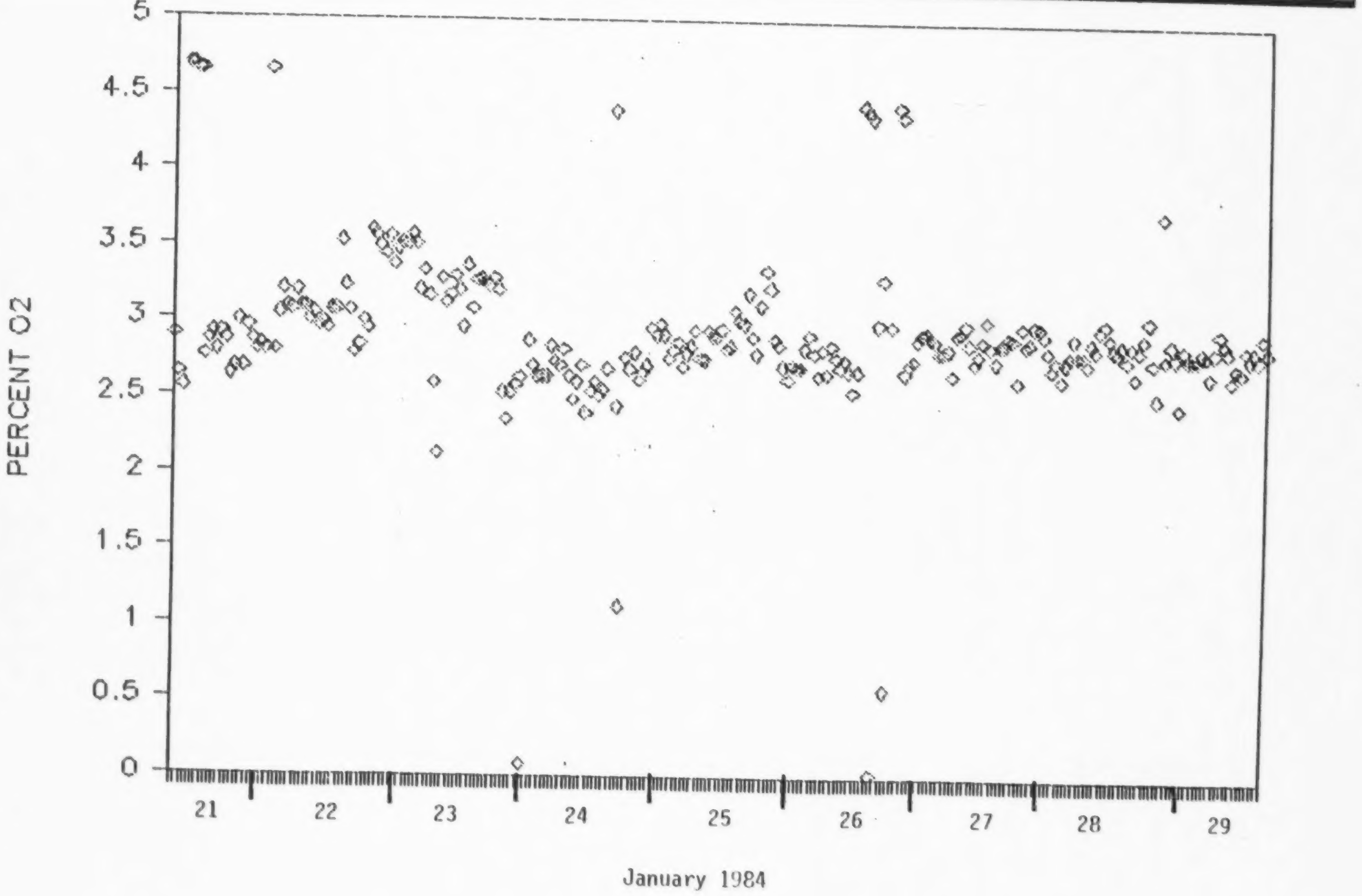
- CONTROLLED CONDENSATION
  - -- SO_2, SO_3

COMPREHENSIVE TESTING (CONCLUDED)

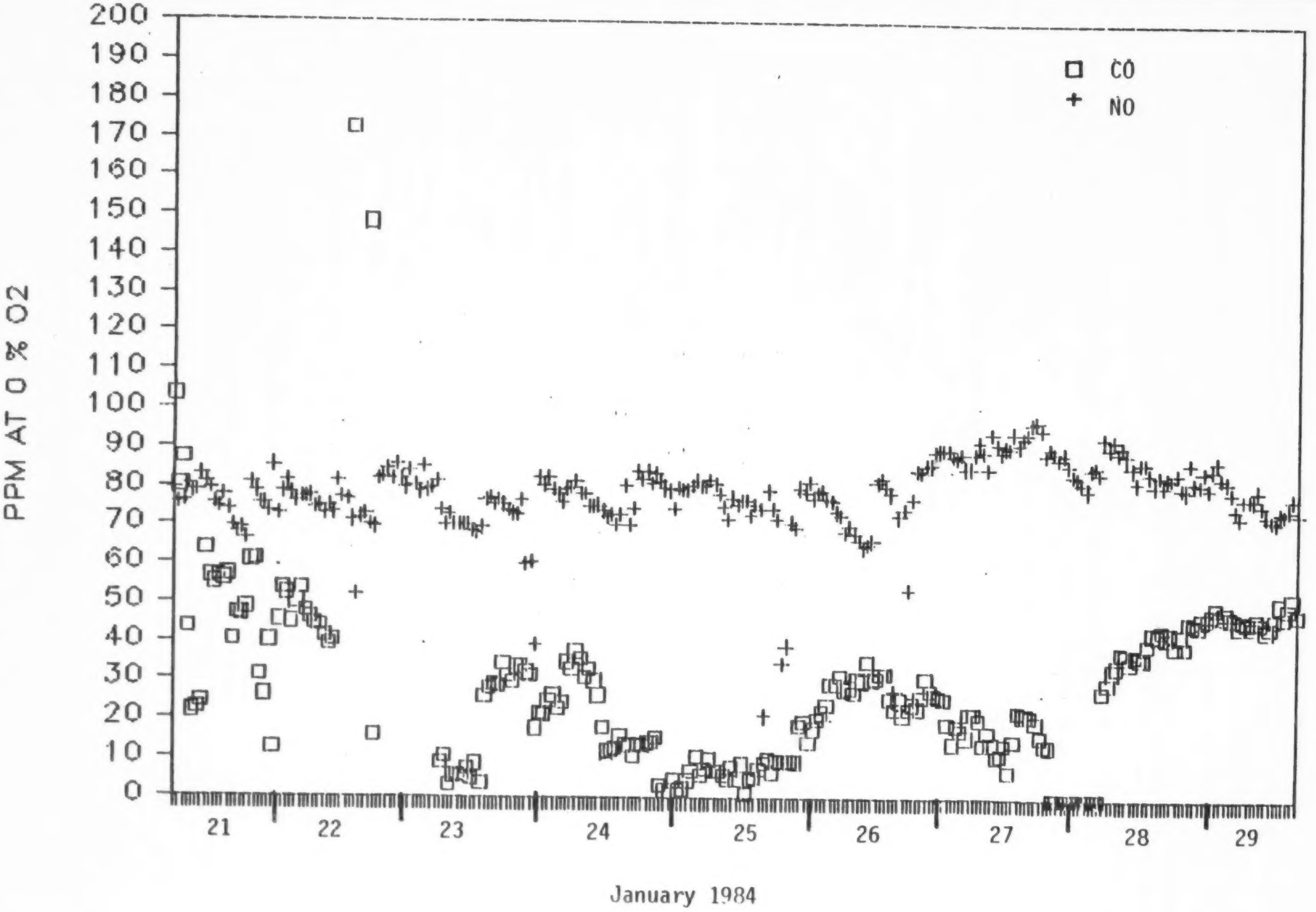
TEST PLAN (CONCLUDED)

- N_2O
  - GRAB SAMPLE
- TOTAL VOLATILE ORGANICS (C_1-C_6)
  - GRAB SAMPLE
- CONTINUOUS MONITORS (NO_X, CO, CO_2, O_2, SO_2)
- FUEL
  - PROXIMATE, ULTIMATE, HHV
  - 73 TRACE ELEMENTS
- STEAMER/BURNER OPERATING DATA
  - FUEL:
    - FLOW
    - T
  - FEEDWATER
    - FLOW
    - T
  - STEAM
    - T
    - P
  - PRIMARY AIR
    - FLOW
    - T
  - SECONDARY AIR FLOW

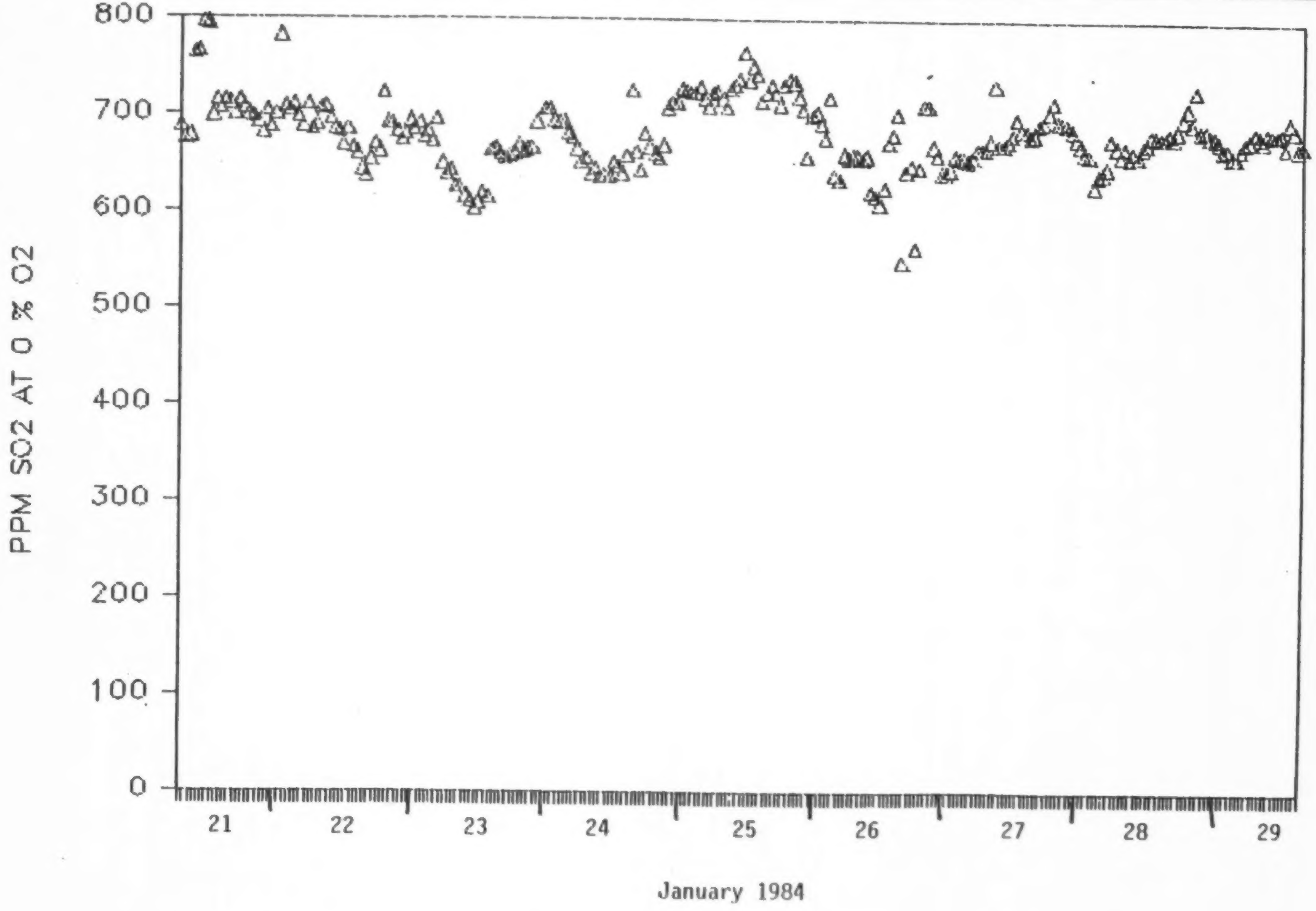
STACK GAS O_2


PERCENT O2
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
21
22
23
24
25
26
27
28
29
January 1984

CO, NO EMISSIONS



SO_2 EMISSIONS



APPENDIX E - TEOR Ad Hoc Committee

An ad hoc committee was formed to ensure transfer of technology developed in this program to industry in a timely fashion. This committee was comprised of representatives from manufacturers and users of oil field steamers, local and federal regulatory agencies, and burner manufacturers. Attendance lists for each of the three meetings held during this program are given in this Apendix.

TEOR AD-HOC COMMITTEE MEETING

ATTENDEES - 1/12/82

COMMITTEE MEMBER	COMPANY	TELEPHONE
Robert Ferraro	John Zinc Company	(918) 747-1371
Peter Nutcher Anthony Elliott	Process Combustion Corporation	(412) 561-6200
Sherman Eaton Temple Voorheis	Coen Company, Inc.	(415) 697-0440
Ted Davies	North American Manufacturing Company	(216) 271-6000
Walter Karlau	Peabody Engineering Company	(203) 327-7000
Berwin King	Struthers Thermo Flood Corp.	(316) 221-4050
Ken Warren	C.E. Natco	(918) 663-9100
Sam Davis	Chevron U.S.A.	(713) 241-1455
Don Harvey	Environmental Protection Agency Region 9	(415) 974-8223
Tom Paxson	Kern County Air Pollution Control District	(805) 861-3682
W. Steven Lanier	Combustion Research Branch-MD-65 Environmental Protection Agency	(919) 541-2432
Alan Goodley	Energy Strategy Development Branch State of California Air Resources Board	(919) 322-6020
Harold Podall	Control Technology Systems Division Fossil Energy (FE-23) U.S. Department of Energy	(301) 353-2843
Roy Payne Glenn England Yul Kwan Tom Tyson	Energy and Environmental Research Corp.	(714) 552-1803
Bill Nurick	Energy Systems Associates	(714) 730-5990

TEOR AD-HOC COMMITTEE

ATTENDEES - 6/15/83

COMMITTEE MEMBER	COMPANY	TELEPHONE
Larry Waterland	Acurex	(415) 964-3200
Mike Perlsweig	DOE - Washington	(301) 353-4399
Steve Lanier	Combustion Research Branch-MD-65 Environmental Protection Agency	(919) 541-2432
Jack Hagan	Peabody Engineering Company	(203) 327-7000
Tony Elliott	Process Combustion Rep.	(714) 891-7200
Ken Warren	C.E. Natco	(918) 599-6746
Bob Ferraro	John Zinc Company	(213) 402-0199
Roger Noble	John Zinc Company	(918) 747-1371
Mike Osborne	Environmental Protection Agency-RTP	(919) 541-4113
Alan Goodley	Carb	(916) 322-6020
Don Hendricks	North American Manufacturing Company	(805) 871-5191
Don Moreland	North American Manufacturing Company	(216) 271-6000
Kent Kitchingman	Environmental Protection Agency Region 9	(415) 974-8380
Kelly Smith	Chevron U.S.A.	(415) 680-3428
Glenn England Yul Kwan Tom Tyson Roy Payne	Energy and Environmental Research Corp.	(714) 859-8851

TEOR AD-HOC COMMITTEE MEETING

ATTENDEES - 2/7/84

COMMITTEE MEMBER	COMPANY	TELEPHONE
Glenn England Yul Kwan Roy Payne Mike Heap	Energy and Environmental Research Corp	(714) 859-8851
Ken Warren	C.E. Natco	(918) 599-6746
Loren Wood	HSMC Thermatics	(805) 327-7001
Frank Eldridge Don Hendricks	North American Manufacturing Company	(805) 871-5191
Berwin King	Struthers Thermo Flood Corp.	(316) 221-4050
Marie Freiburger Kevin Prochaska	Chevron U.S.A.	(415) 680-3493
Rich Pogers Tim Morton	Chevron U.S.A.	(805) 393-1312
Dick Bell	John Zink Company	(213) 563-1151
Pete Nutcher	Process Combustion Corporation	(412) 257-2080
Jack Hagan	Peabody Engineering Company	(203) 327-7000
John Link	Link Assoc. Peabody Engineering Company	(714) 241-9127
Kirk Chapman	Coen Company, Inc.	(415) 697-0440
Mike Osborne	Environmental Protection Agency-RTP	(919) 541-4113
Alan Goodley	Carb	(916) 322-6020
Larry Waterland	Acurex	(415) 564-3200

SO_2 EMISSIONS